PetroHunter Energy Corp
Form 10-K
January 13, 2009

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

þ	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the fiscal year ended September 30, 2008
	or
o	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the transition period from to

Commission file number: 000-51152

PETROHUNTER ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

Maryland (State or other jurisdiction of incorporation or organization)	98-0431245 (I.R.S. Employer Identification No.)
1600 Stout Street, Suite 2000 Denver, Colorado (Address of principal executive offices)	80202 (Zip Code)

Registrant's telephone number, including area code:
(303) 572-8900

Securities registered pursuant to Section 12(b) of the Act:
None

Securities registered pursuant to Section 12(g) of the Act:
Common Stock, $0.001 par value
(Title of class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ   No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer o	Accelerated filer o
Non-accelerated filer o	Smaller reporting company þ

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No þ

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter: $25.8 million as of March 31, 2008.

As of December 31, 2008, the registrant had 375,218,544 shares of common stock outstanding.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Report constitute "forward-looking statements". These statements, identified by words such as "plan", "anticipate", "believe", "estimate", "should", "expect" and similar expressions includ expectations and objectives regarding our future financial position, operating results and business strategy. These statements reflect the current views of management with respect to future events and are subject to risks, uncertainties and other factors that may cause our actual results, performance or achievements, or industry results, to be materially different from those described in the forward-looking statements. Such risks and uncertainties include those set forth under the caption "Management's Discussion and Analysis of Financial Condition and Results of Operation" and elsewhere in this Annual Report. We do not intend to update the forward-looking information to reflect actual results or changes in the factors affecting such forward-looking information. We advise you to carefully review the reports and documents we file from time to time with the Securities and Exchange Commission (the "SEC").

All subsequent written and oral forward-looking statements attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements. We assume no duty to update or revise our forward-looking statements based on changes in internal estimates or expectations or otherwise.

CURRENCIES

All amounts expressed herein are in U.S. dollars unless otherwise indicated.

GLOSSARY

Certain Definitions

Terms used to describe quantities of oil and natural gas and marketing

- Bbl — One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or other liquid hydrocarbons.
- Bcf — One billion cubic feet of natural gas.
- Bcfe — One billion cubic feet of natural gas equivalent.
- BOE—One barrel of oil equivalent, converting natural gas to oil at the ratio of 6 Mcf of natural gas to 1 Bbl of oil.
- BTU —British Thermal Unit.
- Condensate —An oil-like liquid produced in association with natural gas production that condenses from natural gas as it is produced and delivered into a separator or similar equipment and collected in tanks at each well prior to the

delivery of such natural gas to the natural gas gathering pipeline system.

- MBbl —One thousand barrels.

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- Mcf —One thousand cubic feet of natural gas.

- Mcfe—One thousand cubic feet of natural gas equivalent, converting oil or condensate to natural gas at the ratio of 1 Bbl of oil or condensate to 6 Mcf of natural gas.

- MMBbl —One million barrels of oil or other liquid hydrocarbons.

- MMcf —One million cubic feet of natural gas.

- MBOE —One thousand BOE.

- MMBOE —One million BOE.

- MMBTU —One million British Thermal Units.

Terms used to describe the Company's interests in wells and acreage

- Gross oil and natural gas wells or acres —The Company's gross wells or gross acres represent the total number of wells or acres in which the Company owns a working interest.

- Net oil and natural gas wells or acres — Determined by multiplying "gross" oil and natural gas wells or acres by the working interest that the Company owns in such wells or acres represented by the underlying properties.

- Prospect—A location where hydrocarbons such as oil and gas are believed to be present in quantities which are economically feasible to produce.

Terms used to assign a present value to the Company's reserves

- Standardized measure of discounted future net cash flows, after income taxes — The present value, discounted at 10%, of the after-tax future net cash flows attributable to estimated net proved reserves. The Company calculates this amount by assuming that it will sell the oil and natural gas production attributable to the proved reserves estimated in its independent engineer's reserve report for the oil and natural gas spot prices on the last day of the year, adjusted for quality and transportation. The Company also assumes that the cost to produce the reserves will remain constant at the costs prevailing on the date of the report. The assumed costs are subtracted from the assumed revenues resulting in a stream of future net cash flows. Estimated future income taxes, using rates in effect on the date of the report, are deducted from the net cash flow stream. The after-tax cash flows are discounted at 10% to result in the standardized measure of the Company's proved reserves.

- Standardized measure of discounted future net cash flows before income taxes — The discounted present value of proved reserves is identical to the standardized measure described above, except that estimated future income taxes are not deducted in calculating future net cash flows. The Company discloses the discounted present value without deducting estimated income taxes to provide what it believes is a better basis for comparison of its reserves to the producers who may have different income tax rates.

Terms used to classify the Company's reserve quantities

The Securities and Exchange Commission ("SEC") definition of proved oil and natural gas reserves, per Regulation S-X, is as follows:

- Proved oil and natural gas reserves — Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made as defined in Rule 4-10(a)(2).

Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(a) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (1) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(b) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(c) Estimates of proved reserves do not include the following: (1) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (2) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (3) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (4) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

- Proved developed reserves —Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods as defined in Rule 4-10(a)(3).

- Proved undeveloped reserves —Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required as defined in Rule 4-10(a)(4).

Terms used to describe the legal ownership of the Company's oil and natural gas properties

- Working interest — A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas. A working interest owner who owns a portion of the working interest may participate either as operator or by voting its percentage interest to approve or disapprove the appointment of an operator and drilling and other major activities in connection with the development and operation of a property.

Terms used to describe seismic operations

- Seismic data — Oil and natural gas companies use seismic data as their principal source of information to locate oil and natural gas deposits, both to aid in exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones which digitize and record the reflected waves. Computers are then used to process the raw data to develop an image of underground formations.

- 2-D seismic data — Until recently, 2-D seismic survey data has been the standard acquisition technique used to image geologic formations over a broad area. 2-D seismic data is collected by a single line of energy sources which reflect seismic waves to a single line of geophones. When processed, 2-D seismic data produces an image of a single vertical plane of sub-surface data.

- 3-D seismic data — 3-D seismic data is collected using a grid of energy sources, which are generally spread over several miles. A 3-D survey produces a three dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is generally considered a more reliable indicator of potential oil and natural gas reservoirs in the area evaluated.

Terms used to describe certain property disclosures

- Compressional events — Earth forces that are horizontal, compressional (tectonic) forces causing rocks to compress or shorten commonly into anticlines (hills) with associated breakage of rocks (faults) in which one slab of rock is forced over another buckling the earth into a series of hills (anticlines) and associated faults. These buckling forces can occur repeatedly throughout geologic time and any such time is referred to as a compressional event. They are the opposite of extensional or tensional forces where rocks are pulled apart.

- Drill stem tests — A test of a reservoir conducted within a well that has been drilled but not cased; i.e. in an open hole. The test involves isolating the desired rock unit in the subsurface by a series of packers which separate the rock being investigated from fluids or gases from horizons above or below it. The Drill Stem Test (or DST) is designed to allow the fluids and gases to flow into a string of pipe connected to the surface where the rates and volumes of the material from the reservoir are measured to determine commerciality of the well.

- Fractured shales and basin centered gas accumulations — Types of unconventional reservoirs being actively developed in the world in which hydrocarbons are stored within shales and low permeability sandstones in a continuous phase. They generally produce little or no water. They are different than conventional reservoirs where oil and gas are buoyed by water and hydrocarbons are pushed to the well due to the buoyancy of oil and gas relative to water (lighter and forced out of the formation). Conventional accumulations typically are found on buried hills (anticlines) in the subsurface whereas fractured shales and basin centered gas accumulations are found in the central parts of central parts of basins (synclines).

- Gas window — Refers to the depth at which the process of turning kerogen into gas can occur – generally found in the 100-200+ degree Celsius interval (3-6 km depth).

- Imbricate thrust faults — When rocks are broken in the subsurface by compressional or tensional forces (tectonic) they are either pushed together or override adjacent rocks in a type of fault known as a reverse fault or thrust fault. When several of these thrust or reverse faults are found in succession, they are said to be imbricated thrust faults. Conversely, if the rocks are pulled apart by tectonic forces the faults where the rocks are broken are said to be normal (extensional) faults.

- Lenticular sand bodies — Conventional reservoirs that contain hydrocarbons are generally contained in either sandstones or carbonates. Sandstone reservoirs come in many different geometries; some very widespread or blanket sand bodies, some in long ribbons or strips of sand or channelized sand bodies, sometimes they occur as a lense of sand; thinning in all directions from their thickest part and these are called lenticular sand bodies and describes the geometry of the sandstone reservoir.

- Mudlog — The record of a well that is being drilled that contains a description of the types of rocks being encountered in the subsurface and brought to the surface after being drilled by mud circulated in the borehole is called a mudlog. Commonly, the presence of hydrocarbons is also indicated on the mudlog as recorded by a heated gas wire and recording device measuring the presence of hydrocarbons in the circulating mud at the surface. The mudlog is generated to describe the rocks encountered, the presence or absence of hydrocarbons, and a variety of other measurements of the circulating mud parameters such as its weight, viscocity, drill bit size and type of bit.

- Oil window— Depth at which the process of turning kerogen into oil can occur – generally from 6,000-7,000 ft. to 13,000-15,000 ft.

- Petrophysical analyses — After a well has been drilled, most wells are logged with a series of devices that measure properties of the rock including its resistivity, its porosity as measured by it sonic properties or density properties. The combination of all of the measurements is then evaluated by an expert in well log evaluations and this person is referred to as a petrophysicist. A petrophysical analysis is the result of this investigation and is designed to evaluate the depth, thickness, presence and commerciality of hydrocarbons in the well.

- Strike-slip movement — Strike-slip movement is the lateral movement of one slab of rock relative to an adjacent slab. It is generated by earth (tectonic) forces where rocks break and are forced to move adjacent to each other in a generally horizontal direction. Movement along the plane of the fault is said to be in the strike direction (as opposed to the dip direction--across the movement). So a strike slip motion is motion along the fault parallel to the map direction of the fault when observed from the surface (or on a map).

- Total Organic Content ("TOC") — Oil and gas form from conversion of organic matter when buried, and converted into petroleum by the combined effects of heat and time. Buried organic matter is called kerogen, and a petroleum source is any rock that contains enough kerogen to generate oil or gas. Most good source rocks are shales with a TOC of at least 2% and can generate oil or natural gas depending on the type of kerogen and the pressure and temperature they are subjected to.

- Unconventional fractured shale play — Unconventional reservoirs were described above as generally not having a water buoyancy component. Oil and gas are mostly derived from a source bed generally an organically rich shale or coal. Shales generally do not have as much storage capacity as more porous sand or carbonate reservoirs; however where they are broken up by earth (tectonic) forces they sometimes fracture and hydrocarbons are stored in these fractured spaces. Hydrocarbons focused on a specific, hydrocarbon bearing, fractured shale are said to be in an unconventional fractured shale play.

- Under-balanced — In the subsurface, rocks experience different pressures and temperatures related to the fluids and gases present in response to increasing depth of burial. If a well only encounters water bearing rock, it is said to be hydrostatic or normally pressured and pressures will reflect the weight of water or 0.43 psi (pounds per square inch) of pressure per foot drilled. If however, pressures are encountered in the rocks in excess of this pressure they are said to be overpressured; i.e. greater than 0.43 psi per foot; or underpressured if less than 0.43 psi per foot. Drilling operations vary considerably if among normally pressured, under-balance (under-pressured) and over-pressured rocks.

- Vitrinite reflectance — A measurement of the maturity of organic matter with respect to whether it has generated hydrocarbons or could be an effective source rock. The reflectivity of at least 30 individual grains of vitrinite from a rock sample is measured under a microscope. The measurement is given in units of reflectance, % Ro, with typical values ranging from 0% Ro to 3% Ro. Strictly speaking, the plant material that forms vitrinite did not occur prior to Ordovician time, although geochemists have established a scale of equivalent vitrinite reflectance for rocks older than Ordovician.

PETROHUNTER ENERGY CORPORATION

FORM 10-K

FOR THE FISCAL YEAR ENDED
SEPTEMBER 30, 2008
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PART I

ITEM 1. BUSINESS

General

PetroHunter Energy Corporation (collectively, with its subsidiaries, referred to herein as “PetroHunter”, “Company”, “we”, “us” or “our”), formerly Digital Ecosystems Corp. (“Digital”), through the operations of its wholly-owned subsidiaries, is a global oil and gas exploration and production company with primary assets consisting of working interests in oil and gas leases and related assets in various oil and natural gas prospects. We are a development stage global oil and gas exploration and production company whose business consists principally of acquiring and developing unconventional and conventional natural gas and oil prospects that we believe have a high probability of economic success. Since our inception in 2005, our business activities have been financed by raising capital through the sale of common stock and convertible notes. Currently, we own property in Colorado, where we have drilled five wells on our Buckskin Mesa property; in Australia, where we have drilled one well on our property in the Northern Territory; and in Montana, where we hold a land position in the Bear Creek area. The wells on these properties have not yet commenced oil and gas production. During the period ended September 30, 2008, we owned working interests in eight additional wells in Colorado which were operated by EnCana Oil & Gas USA (“EnCana”) and were producing gas as of September 30, 2008. In December 2008, we sold our interests in these wells. In November 2007, we sold 66,000 net acres of land and two wells in Montana and 173,738 acres of land in Utah and on May 30, 2008, we sold 605 net acres, 16 wells which had been drilled and cased but not completed or connected to a pipeline and rights to participate in an additional 8 wells in the Southern Piceance Basin in Colorado. Our remaining properties are managed and operated in two geographic areas: Piceance Basin, Colorado and Australia.

Digital was incorporated on February 21, 2002, under the laws of the State of Nevada. On February 10, 2006, Digital entered into a Share Exchange Agreement (the “Agreement”) with GSL Energy Corporation (“GSL”) and certain shareholders of GSL pursuant to which Digital acquired more than 85% of the issued and outstanding shares of common stock of GSL, in exchange for shares of Digital’s common stock. On May 12, 2006, the parties to the Agreement completed the share exchange and Digital changed its business to the business of GSL. Subsequent to the closing of the Agreement, Digital acquired all the remaining outstanding stock of GSL, and effective August 14, 2006, Digital changed its name to PetroHunter Energy Corporation and reincorporated under the laws of the State of Maryland.

As a result of the Agreement, GSL became a wholly-owned subsidiary of PetroHunter. Since this transaction resulted in the former shareholders of GSL acquiring control of PetroHunter, for financial reporting purposes the business combination was accounted for as an additional capitalization of PetroHunter (a reverse acquisition with GSL as the accounting acquirer).

On November 8, 2005, GSL formed PaleoTechnology, Inc. (“Paleo”) as a wholly-owned subsidiary for the purpose of exploring and developing new products and processes using by-products of petroleum extraction environments. On September 11, 2006, GSL formed Petronian Oil Corporation, now known as PetroHunter Heavy Oil Ltd., as a wholly-owned subsidiary for the purpose of holding and developing its heavy oil assets. In October 2006, GSL Energy Corporation changed its name to PetroHunter Operating Company. In March 2006, GSL acquired a 50% interest in four exploration permits held by Sweetpea Corporation Pty Ltd. (“Sweetpea”), an Australian corporation; and effective January 1, 2007, we acquired 100% of the common shares of Sweetpea from MAB Resources, LLC (“MAB”), a Delaware limited liability company which is also in the business of oil and gas exploration and development, and is our largest shareholder. Sweetpea is the record owner of four exploration permits issued by the Northern Territory of Australia. On October 20, 2006, PetroHunter formed PetroHunter Energy NT Ltd., now known as PetroHunter Australia Ltd. (“PetroHunter Australia”) for the purpose of holding and developing its assets in Australia, but no assets were assigned into PetroHunter Australia. In May 2007, we approved the dissolution of PetroHunter Australia.

Our annual report on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K, as well as any amendments to such reports and all other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available free of charge to the public on the Company's website at www.petrohunter.com. To access the

Company's SEC filings, select "SEC FILINGS" under the INVESTOR RELATIONS tab on the Company's website. You may also request a copy of these filings at no cost by making written or telephone requests for copies to our principal executive offices at PetroHunter Energy Corporation, Investor Relations, 1600 Stout Street, Suite 2000, Denver, CO 80202. The telephone number is (303) 572-8900, the facsimile number is (720) 889-8371. Our periodic and current reports filed with the SEC can be found on our website and on the SEC's website at www.sec.gov.

Business Strategy

During the period ended September 30, 2008 we continued to focus our property development efforts in two core areas: Australia and the Piceance Basin, Colorado. Accordingly, during the year ended September 30, 2008 we completed a series of asset sale transactions, where we sold assets that we did not consider central to our business plan, in order to reduce a substantial accumulated working capital deficit and provide a path to achieve our future operating objectives in our core development projects. In addition, we sold certain working interests in our areas of focus in Australia and Colorado to Falcon Oil & Gas Ltd. ("Falcon"), a related party, with whom we plan to develop those properties. In August 2008, we entered into an agreement with Falcon to sell a 50% working interest in four exploration permits covering our 7 million-acre prospect in the Northern Territory, Australia (the "Beetaloo Basin"), and closed this transaction on September 30, 2008. We will continue to be the operator in the Beetaloo Basin. We also entered into a binding agreement with Falcon to sell a 25% working interest in five wells located within our 20,000-acre Buckskin Mesa Project located in the Piceance Basin, Colorado, and to undertake a completion and testing program with respect of these five wells, and closed this transaction in November 2008. The agreement provides Falcon an option ("Buckskin Option") to purchase a 50% working interest in our entire Buckskin Mesa Project, and also gives Falcon the option to become the operator if additional consideration is paid upon the exercise of the Buckskin Option. The testing and completion activities are underway and are expected to be completed early in 2009, at which time Falcon will have a limited window of time in order to determine whether it will exercise the Buckskin Option. In the event Falcon elects not to exercise the Buckskin Option for any reason, we will be free to pursue other potential development partners in relation to our Buckskin Mesa Project.

Marc A. Bruner, our largest beneficial shareholder, is the Chairman, President, and Chief Executive Officer and a Director of Falcon. Falcon advised PetroHunter and announced that Mr. Bruner did not participate in the vote by the Falcon Board of Directors when the Falcon board voted to approve the agreements with respect to the sale of the working interests in the Buckskin Mesa and Beetaloo Basin Projects. We obtained a fairness opinion with respect to transactions contemplated by these agreements.

Piceance Basin, Colorado

Buckskin Mesa Project. As of September 30, 2008, we have drilled five wells within our 20,000-acre Buckskin Mesa Project area. All five wells are currently shut-in, awaiting the construction of a gas gathering system. The first PetroHunter operated well, the Anderson 6-16, was drilled to a total depth of 10,785 feet through the Williams Fork, Cozzette, Corcoran, and Sego sands into the Cretaceous Mancos Shale. The initial well was followed in close succession with the drilling of the Anderson 13-10, the Lake 16-21, Anderson 4-21, and the Lake 6-22 wells. Completion operations have begun on the Lake 16-21 and Lake 6-22. The remaining wells will commence as soon as possible after the gathering system is in place, as discussed further in "Marketing and Pricing - Natural Gas Marketing" later in this section. Future development drilling is expected to follow thereafter.

Piceance Project. We also own an additional 1,233 gross acres and 482 net acres in the Piceance Basin. As of September 30, 2008, all of our producing wells are located in this area, along with other proved undeveloped locations. We reasonably expect continued gas production from the Williams Fork formation and from the deeper Cozzette, Corcoran, and Sego sands, all of Cretaceous age.

Australia

Northwest Shelf Project. In March 2007, Sweetpea Petroleum (“Sweetpea”) acquired Exploration Permit #WA-393-P in the Barrow Sub-Basin of the Carnavon Basin on the Northwest Shelf of Australia. Subsequently, Sweetpea acquired the available seismic on and adjacent to the permit and mapped four stratigraphic horizons. Initial seismic mapping of the permit area demonstrates three structures: one structure entirely on the block and two partially on the block in water depths of approximately 600 feet. These structures are within about 80 kilometers of the major discovery in the Triassic Mungaroo Formation at the Chevron Clio-1 well on the Northwest Shelf in this basin, which occur in deeper water depths of about 3,000 feet. Additional geophysical analysis and mapping are ongoing on the block.

Beetaloo Basin Project. Sweetpea also has four exploration permits in the Northern Territory, comprising the Beetaloo Basin Project. In September 2007, Sweetpea drilled and cased one well the Shenandoah #1 to a total depth of 1,555 meters (4,740 feet) in the area covered by Exploration Permit ("EP") 98 in the Beetaloo Basin. The test was a twin (50 meter distance) from the Balmain #1 well and was designed to test the Bessie Creek Formation at a depth of approximately 3,000 meters. The well was completed to the drilled depth of 1,555 meters and cased, in anticipation of later completing the well to the targeted total depth. It is expected that this well will be deepened to evaluate the petroleum potential there. Additionally, we plan to drill four wells prior to December 31, 2009 to fulfill our obligations under EP 98 and EP 117, with additional activity planned for EP 76 and EP 99. Evaluation of drilling results in the Shenandoah #1 and seven other existing wells in the Beetaloo Basin indicate oil and gas prospectivity in the Kyalla Shale and a drilling and stimulation program to test these horizons is planned to commence in the Spring of 2009.

In addition to the Beetaloo Basin and Northwest Shelf Projects, we have also applied for two additional exploration permits in the Northern Territory in Australia covering an additional 1.5 million acres, which are adjacent to our Beetaloo Basin Project acreage.

Montana Assets

In November 2007, we sold all of our interest in our Heavy Oil Projects, including the West Rozel, Fiddler Creek, and Promised Land Projects in Utah and Montana. We continue to hold an acreage position of 15,990 net acres where our objective is to produce methane from multiple thin coal lenses; however this project is currently on hold.

Financing Strategy

During the year ended September 30, 2008, we completed a series of financing and asset sale transactions that were intended to reduce a substantial accumulated working capital deficit and provide a path to achieve our future operating objectives in our core projects. In addition, our transactions with Falcon to sell significant working interests in our core properties were consummated in order to reduce our aggregate capital requirements while increasing the probability of overall success with our core development projects.

While we have completed the sale of the majority of our non-core assets as of December 31, 2008, we currently hold a significant number of shares of Falcon stock, which initially comprised $20.0 million of the total consideration of the Beetaloo Basin transaction. Additionally, if Falcon exercises the Buckskin Option, we expect to realize significant additional consideration and Falcon will carry significant capital costs in our Buckskin Mesa Project. We also believe we have viable debt and/or equity financing alternatives that together, will allow us to achieve our operating plans and objectives. However, the value of the Falcon stock we have received from the Beetaloo Basin transaction has been extremely volatile since we entered into the definitive agreements with Falcon in August 2008, and the overall value of the stock had declined to approximately one third of its transaction value as of December 31, 2008. Further, we entered into a secured note agreement with Falcon in October 2008 where we borrowed $5.0 million against the value of the Falcon stock. There can be no assurance we will be successful in ultimately realizing sufficient net cash proceeds from the sale of the Falcon stock, in order for this asset to become a meaningful source of financing for the development of our properties and financing our ongoing operating costs. Similarly, there can be no assurance Falcon will exercise the Buckskin Option, and we may be unable to successfully secure additional debt and/or equity financing in amounts and under terms that will allow us to meet our operating plans and objectives.

Marketing and Pricing

We have historically derived our revenues principally from the sale of natural gas and associated condensate production from wells operated by us and others in the Piceance Basin in Colorado. Our revenues have been determined, to a large degree, by prevailing natural gas prices for production situated in the Rocky Mountain Region of the United States, specifically, Colorado. Energy commodity prices in general, and the Company's regional prices in particular, have been highly volatile in the past, and such high levels of volatility are expected to continue in the future. We cannot predict or control the market prices for the sale of our natural gas, condensate, or oil production.

Natural Gas Marketing

We have sold all of our natural gas production to a diverse group of third-party, non-affiliated entities in a portfolio of transactions of various durations and prices (daily, monthly and longer term), under a marketing agreement with EnCana, who is the operator of our 8 producing gas wells in production, which we held until we sold our working interests in these wells on December 30, 2008, effective December 1, 2008. As of September 30, 2008, our customers were predominantly located in the western United States — primarily California and the Pacific Northwest, as well as the Front Range area of Colorado and in Utah. As the Rockies Express Pipeline, LLC (“REX”) becomes operational (as discussed below), this customer base is expected to expand to include customers in the mid-western and eastern United States. The sale of our natural gas was “as produced”. As such, we did not maintain any significant inventories or imbalances of natural gas. We did not have any outstanding, uncollectible accounts for our natural gas sales at September 30, 2008.

We have entered into a Gas Gathering Agreement with CCES Piceance Partners I, LLC (“CCES”), a service provider that gathers, compresses and processes natural gas owned or controlled by us from our producing wells in the Piceance Basin in Colorado. Under this agreement, CCES will expand its facilities capacity in Colorado to accommodate growing volumes from wells in which we own an interest. As part of the Gas Gathering Agreement, we have guaranteed that, should there be a mutual failure to execute a formal agreement for long-term gas gathering services in the future, we will repay CCES for certain costs they have incurred in relation to the development of a gas gathering system and repurchase certain gas gathering assets we sold to CCES. This agreement contains a multi-year commitment for midstream services. These facilities remove natural gas liquids from our gas (and gas of others) making it sufficient quality to be accepted into the natural gas transmission pipelines serving the area. We have contractually secured capacity at this facility for the processing of our natural gas. We believe that the capacity of the midstream infrastructure related to our production will continue to be adequate to allow us to sell essentially all of our available production.

Because local natural gas production typically exceeds local demand for natural gas during non-winter months, the Rocky Mountain Region is usually a net-exporter of natural gas. As a result, natural gas production in Colorado has historically sold at a discount relative to other U.S. natural gas production sources or market areas. These regional pricing differentials or discounts are typically referred to as “basis” or “basis differentials”. We have seen significant basis differentials for our Colorado production versus the Henry Hub (“Henry Hub”) pricing reference point in south Louisiana in the past. This trend continued and actually became more pronounced in 2007 and 2008. As a result, we realized prices that were significantly lower than those received by companies with natural gas production in other regions of the U.S.

During portions of the quarter ending September 30, 2008, we realized natural gas prices that were lower than those seen in previous years in the Colorado region. The market price for natural gas in the Rockies generally, and in Colorado specifically, is influenced by a number of regional and national factors, all of which are unpredictable and are beyond our ability to control. These factors include, among others, weather, natural gas supplies, natural gas demand, and natural gas pipeline capacity to export gas from the Rockies. Continued robust growth in natural gas production from natural gas fields in Colorado during 2007 and 2008, coupled with a nearly 100% utilization of existing natural gas pipeline export capacity, caused natural gas prices in the Rocky Mountain Region to decrease dramatically during our fiscal fourth quarter ended September 30, 2008 and continuing into December 2008. In contrast, with the onset of colder weather, and in response to voluntary producer shut-ins of natural gas production by us and others, the widening basis differentials for Rockies production became much less pronounced during the last calendar quarter of 2007. For example, the differential between prevailing Colorado prices and the benchmark Henry Hub price ranged from more than $5 per MMBtu discount in October 2007 to a narrower discount of approximately $1.20 per MMBtu in December 2007, resulting in an increase in natural gas pricing during this period. In the years past, increases in pipeline capacity to transport production from Rocky Mountain production areas to markets in the west have served to improve (i.e. lower) basis differentials for Colorado natural gas production. (Examples include: Kern River Pipeline — in service May 2003; the Cheyenne Plains Pipeline — in service February 2005; and Rockies Express Pipeline (“REX”) expansion to Cheyenne, Wyoming placed into service on February 14, 2007). These expansions of pipeline export capacity have historically reduced but not entirely eliminated the basis differential for natural gas prices in Colorado when compared to prices at the Henry Hub pricing reference point.

REX begins at the Opal Processing Plant in Colorado and traverses Wyoming and several other states to an ultimate terminus in eastern Ohio. This pipeline is ultimately projected to cover more than 1,800 miles and is designed as a large-diameter (42”), high-pressure natural gas pipeline. REX is an interstate pipeline and is subject to the jurisdiction of the United States Federal Energy Regulatory Commission (“FERC”).

There have been and continue to be numerous other proposed pipeline projects that have been announced to transport growing Rockies and Colorado natural gas production to a variety of geographically diverse markets in different parts of North America. There are numerous such proposals that have been presented to us in recent months, which, if constructed, would provide us with additional outlets and market access for our natural gas production from Colorado. We continuously evaluate such proposals and may make additional commitments to one or more such pipeline projects in the future in an effort to cause additional pipeline infrastructure and capacity to be added to the pipeline network.

Oil Marketing

We market our Colorado condensate (which is an oil-like product that is produced coincident to our natural gas production) from gas wells located in the Piceance Basin to various purchasers. The pricing of our condensate production is based on NYMEX crude futures daily settlement prices, less a negotiated location and transportation discount and is denominated in U.S. dollars per barrel. Our condensate production is gathered from our Colorado well locations by tanker trucks and is then shipped to other locations for injection into crude oil pipelines or other facilities. Through September 30, 2008, revenue from our condensate production in Colorado has been insignificant.

Competition

We operate in the highly competitive oil and gas areas of acquisition and exploration, areas in which other competing companies have substantially larger financial resources, operations, staffs and facilities. Such companies may be able to pay more for prospective oil and gas properties or prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit.

Employees

At September 30, 2008, we had 20 total employees, all full time. In addition, we utilized the services of 10 full time consultants.

Regulation

Oil and Gas Regulation

The availability of a ready market for oil and natural gas production depends upon numerous factors beyond our control. These factors may include, among other things, state and federal regulation of oil and natural gas production and transportation, as well as regulations governing environmental quality and pollution control, state limits on allowable rates of production by a well or proration unit, the amount of oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be “shut-in” because of a lack of an available natural gas pipeline in the areas in which we may conduct operations. State and federal regulations are generally intended to prevent waste of oil and natural gas, protect rights to produce oil and natural gas between owners in a common reservoir, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines and natural gas plants operated by other companies that provide midstream services to us are also subject to the jurisdiction of various federal, state and local agencies.

Our sales of natural gas are affected by the availability, terms and costs of transportation both in the gathering systems that transport the natural gas from the wellhead to the interstate pipelines and in the interstate pipelines themselves. The rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines are regulated by the FERC under the Natural Gas Act, as well as under Section 311 of the Natural Gas Policy Act. Since 1985, the FERC has implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open access, non-discriminatory basis. On February 25, 2000, the FERC issued a statement of policy and a final rule concerning alternatives to its traditional cost-of-service rate-making methodology to establish the rates interstate pipelines may charge for services. The final rule revises the FERC's pricing policy and current regulatory framework to improve the efficiency of the market and further enhance competition in natural gas markets. The FERC is also considering a number of regulatory initiatives that could affect the terms and costs of interstate transportation of natural gas by interstate pipelines on behalf of natural gas shippers, including policy inquiries about natural gas quality and interchangeability, selective discounting of transportation services by pipelines to shippers, and proposed rules governing pipeline creditworthiness and collateral standards. Because these regulatory initiatives have not been made final, the approach the FERC will take and the potential impact on natural gas suppliers remain unclear.

Sales of oil are also affected by the availability, terms and costs of transportation. The rates, terms, and conditions applicable to the interstate transportation of oil by pipelines are regulated by the FERC under the Interstate Commerce Act. The FERC has implemented a simplified and generally applicable ratemaking methodology for interstate oil pipelines to fulfill the requirements of Title XVIII of the Energy Policy Act of 1992 comprised of an indexing system to establish ceilings on interstate oil pipeline rates.

If we conduct operations on federal, tribal or state lands, such operations must comply with numerous regulatory restrictions, including various operational requirements and restrictions, nondiscrimination statutes and royalty and related valuation requirements. In addition, some operations must be conducted pursuant to certain on-site security regulations, bonding requirements and applicable permits issued by the Bureau of Land Management ("BLM") or Minerals Management Service, Bureau of Indian Affairs, tribal or other applicable federal, state and/or Indian Tribal agencies.

The Mineral Leasing Act of 1920 ("Mineral Act") prohibits direct or indirect ownership of any interest in federal onshore oil and gas leases by a foreign citizen of a country that denies "similar or like privileges" to citizens of the United States. Such restrictions on citizens of a non-reciprocal country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and gas lease. If this restriction is violated, the corporation's lease can be canceled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. We own interests in numerous federal onshore oil and gas leases. It is possible that holders of our equity interests may be citizens of foreign countries, which could be determined to be citizens of a non-reciprocal country under the Mineral Act.

See "Risk Factors" for a discussion of the risks involved in our international operations.

Environmental Regulations

General. Our exploration, drilling and production activities from wells and natural gas facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing oil, natural gas and other products are subject to stringent federal, state and local laws and regulations governing environmental quality, including those relating to oil spills and pollution control. Although such laws and regulations can increase the cost of planning, designing, installing and operating such facilities, it is anticipated that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations governing the release of materials in the environment or otherwise relating to the protection of the environment, will not have a material effect upon our business operations, capital expenditures, operating results or competitive position.

Solid and Hazardous Waste. Legislation has been proposed in the past and continues to be evaluated in Congress from time to time that would reclassify certain oil and gas exploration and production wastes as "hazardous wastes". This reclassification would make these wastes subject to much more stringent storage, treatment, disposal and clean-up requirements, which could have a significant adverse impact on our operating costs. Initiatives to further regulate the disposal of oil and gas wastes are also proposed in certain states from time to time and may include initiatives at the county, municipal and local government levels. These various initiatives could have a similar adverse impact on our operating costs.

Although oil and gas wastes generally are exempt from regulation as hazardous wastes (“Hazardous Wastes”), under the federal Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes, it is possible some wastes the Company generates presently or in the future may be subject to regulation under RCRA and state analogs. The Environmental Protection Agency (“EPA”) and various state agencies have limited the disposal options for certain wastes, including hazardous wastes and is considering adopting stricter disposal standards for non-hazardous wastes. Furthermore, certain wastes generated by our oil and natural gas operations that are currently exempt from treatment as Hazardous Wastes may in the future be designated as Hazardous Wastes under the RCRA or other applicable statutes, and therefore be subject to more rigorous and costly operating and disposal requirements.

Superfund. The regulatory burden of environmental laws and regulations increases our cost and risk of doing business and consequently affects our profitability. The Federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault, on certain classes of persons with respect to the release of a "hazardous substance" into the environment. These persons include the current or prior owner or operator of the disposal site or sites where the release occurred and companies that transported, disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for the federal or state governments to pursue such claims. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the potentially responsible parties ("PRP") the costs of such action. Although CERCLA generally exempts "petroleum" from the definition of Hazardous Substance, in the course of its operations, we have generated and will generate wastes that fall within CERCLA's definition of Hazardous Substances. We may also be an owner or operator of facilities on which Hazardous Substances have been released. We may be responsible under CERCLA for all or part of the costs to clean up facilities at which such substances have been released and for natural resource damages, as a past or present owner or operator or as an arranger. To our knowledge, we have not been named a PRP under CERCLA nor have any prior owners or operators of its properties been named as PRP's related to their ownership or operation of such property.

National Environmental Policy Act. As noted, the federal National Environmental Policy Act ("NEPA") provides that, for major federal actions significantly affecting the quality of the human environment, the federal agency taking such action must prepare an Environmental Impact Statement ("EIS"). In the EIS, the agency is required to evaluate alternatives to the proposed action and the environmental impacts of the proposed action and of such alternatives. Our actions, such as drilling on federal lands, to the extent the drilling requires federal approval, may trigger the requirements of the NEPA, and may trigger the requirement that an EIS be prepared. The requirements of the NEPA may result in increased costs, significant delays and the imposition of restrictions or obligations, including but not limited to the restricting or prohibiting of drilling on our properties.

Oil Pollution Act. The Oil Pollution Act of 1990 ("OPA"), which amends and augments oil spill provisions of the Clean Water Act ("CWA"), imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge or, in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. The OPA assigns liability, which generally is joint and several, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses and limitations exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, we could be liable for costs and damages.

Air Emissions. Our operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. Federal and state laws generally require new and modified sources of air pollutants to obtain permits prior to commencing construction, which may require, among other things, stringent, technical controls. Other federal and state laws designed to control hazardous (toxic) air pollutants, might require installation of additional controls. Administrative enforcement agencies can bring actions for failure to strictly comply with air pollution regulations or permits and generally enforce compliance through administrative, civil or criminal enforcement actions, resulting in fines, injunctive relief and imprisonment.

Clean Water Act. The CWA restricts the discharge of wastes, including produced waters and other oil and natural gas wastes, into waters of the United States, a term broadly defined. Under the Clean Water Act, permits must be obtained for the routine discharge pollutants into waters of the United States. The CWA provides for administrative, civil and criminal penalties for unauthorized discharges, both routine and accidental, of pollutants and of oil and hazardous substances. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations that may require permits to discharge storm water runoff, including discharges associated with construction activities.

Endangered Species Act. The Endangered Species Act (“ESA”) was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imputed on activities adversely affecting that species’ habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We conduct operations on federal oil and natural gas leases that have species, such as raptors that are listed as threatened or endangered and also sage grouse or other sensitive species, that potentially could be listed as threatened or endangered under the ESA. The U.S. Fish and Wildlife Service must also designate the species’ critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. If we were to have a portion of our leases designated as critical or suitable habitat, it may adversely impact the value of the affected leases.

OSHA and other Regulations. We are subject to the requirements of the federal Occupational Safety and Health Act (“OSHA”) and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require a company to organize and/or disclose information about hazardous materials used or produced in its operations.

We believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us. We believe that the operators of the properties in which we have an interest are in substantial compliance with applicable laws, rules and regulations relating to the control of air emissions at all facilities on those properties. Although we maintain insurance against some, but not all, of the risks described above, including insuring the costs of clean-up operations, public liability and physical damage, there is no assurance that the insurance will be adequate to cover all such costs, that the insurance will continue to be available in the future or that the insurance will be available at premium levels that justify our purchase. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our financial condition and operations. Compliance with environmental requirements, including financial assurance requirements and the costs associated with the cleanup of any spill, could have a material adverse effect on capital expenditures, earnings or competitive position. We do believe, however, that our operators are in substantial compliance with current applicable environmental laws and regulations. Nevertheless, changes in environmental laws have the potential to adversely affect operations. At this time, we have no plans to make any material capital expenditures for environmental control facilities.

Environmental Matters

While we are not currently subject to environmental-related litigation, the nature of our business is such that we are subject to constantly changing environmental laws and regulations adopted by federal, state and local governmental authorities in both the U.S. and Australia. We would face significant liabilities to the government and/or other third parties for discharges of oil, natural gas, produced water or other pollutants into the air, oil, or water, and the cost to investigate, litigate and remediate such a discharge could materially adversely affect our business, results of operations and financial condition. We encourage readers of this filing to review our risk factors disclosed in our Item 1A of this Form 10-K for the year ended September 30, 2008 for further discussion of our environmental risks.

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ITEM 1A. RISK FACTORS

Risks Related to Our Business

We have a limited operating history and have generated only very limited revenues. We have incurred significant losses and will continue to incur losses for the foreseeable future. If we fail to secure significant sources of funding in the short term, we may not be able to continue in existence.

We are a development stage oil and gas company and have limited operating history and production revenue. Our principal activities have been oil and gas drilling and development activities, raising capital through the sale of our securities and identifying and evaluating potential oil and gas properties.

The report of our independent registered public accounting firm on the financial statements for the year ended September 30, 2008, includes an explanatory paragraph relating to significant doubt or uncertainty of our ability to continue as a going concern. From our inception to September 30, 2008, we have generated a cumulative net loss of $149.5 million. For the 2009 fiscal year, we do not expect our operations to generate sufficient cash flows to provide working capital to pay overhead expenses, the funding of our lease acquisitions, and the exploration and development of our properties. Without adequate financing, we may not be able to successfully develop prospects that we have or that we acquire and we may not achieve profitability from operations in the near future or at all.

As a result of severe cash flow constraints, we have experienced substantial difficulties in meeting our short term cash needs, particularly in relation to our past due vendor commitments. Substantially all of our assets are pledged, and extreme volatility in energy pricing and a deteriorating global economy are creating great difficulties in the capital markets and have greatly hindered our ability to raise debt and/or equity capital. Further, as the result of a series of asset sale transactions, we no longer have significant proven reserves, which increases our difficulties in obtaining traditional financing. During the year ended September 30, 2008 we have also obtained debt financing from related parties which we expect will not continue on any meaningful level in the near future. Although we have made substantial progress in reducing our reported $37.9 million dollar working capital deficit as of September 30, 2007, substantially all of our current assets are concentrated in marketable equity securities we received in conjunction with the sale of a 50% working interest in certain of our Australian assets. Those securities have experienced a dramatic decline in value and remain highly volatile. Further, some of these securities remain restricted from our use. Finally, we continue to have significant lease commitments and drilling obligations to meet, along with an absence of any meaningful revenue and continue to experience a significant operating cash burn rate. These and other risks we are facing may cause us to experience material adverse business consequences, including our inability to continue in existence.

We will have difficulty meeting our short-term cash commitments.

As of September 30, 2008, we had significant contractual obligations to meet certain drilling commitments during our fiscal year ending September 30, 2009, aggregating $25.8 million. We plan to raise additional funds to meet these obligations by selling debt and/or equity securities, by selling our marketable equity securities, or by entering into farm-out agreements or other similar types of arrangements. Financing obtained through the sale of our equity will result in significant dilution to our shareholders. We have granted security interests in our assets to lenders, industry partners and holders of our debentures which limits our ability to sell debt securities since they will be subordinated to our other security interest holders. As of January 2009, substantially all of our assets are pledged. The existence of security interests in our assets restricts our ability to sell those assets. We may be forced to sell assets below market value, and therefore we may not realize the market value or even the carrying value of those assets upon their disposition.

On December 30, 2008, we sold our only revenue producing natural gas properties to a third party in order to address our immediate cash needs. As a result, our ongoing cash burn rate has increased, and our overhead structure remains high, in light of our lack of production revenue.

Our cash flow shortages have created numerous problems for us, and are expected to create further challenges.

From time to time, our ongoing cash shortages have created problems such as liens and foreclosure actions, delays in meeting our debt obligations requiring that we obtain waivers at further cost to us, and have forced us to undertake several asset sale transactions that have resulted in significant losses upon their conveyance. We expect these conditions to continue in the short term; however, we have fewer asset sale options available to us, which adds significant risks to our ability to finance our planned operations.

Our historical results of operations, along with current economic conditions in our industry and in the overall global economy, all serve to increase the difficulty we expect to encounter as we continue to pursue adequate financing for our planned operations through the sale of debt and/or equity securities. In addition, the terms of such sales of securities are not expected to be favorable, and could result in substantial dilution to our shareholders and/or extremely high financing costs.

We continue to carry significant past due vendor obligations, and our inability to pay our vendors on a timely basis may have an adverse effect on our ability to secure their future services.

Although we have made substantial progress in paying down our past due vendor obligations in the U.S. and in Australia during the year ended September 30, 2008, significant past due amounts remain outstanding and the satisfaction of these obligations increases our immediate cash needs. Until all of our past due vendor obligations are fully satisfied and we become current, there remains significant risk that these vendors could take formal collection actions against us, pursue liens or other legal actions, or potentially force us into involuntary bankruptcy. Additionally, our inability to satisfy our vendor obligations on a timely basis may result in irreparable harm to our relationship with them and their willingness to continue to do business with us in the future, under terms that would be acceptable to us. We may be required to make advance payments for services, and some critical and/or uniquely qualified vendors may refuse to continue to do business for us, which would worsen our liquidity challenges and potentially prevent us from meeting our drilling and other operating obligations, and could result in material adverse consequences to us.

We have completed several significant asset dispositions during the year, which leaves us with two primary projects that are both undeveloped and subject to substantial risks.

During the year ended September 30, 2008, we experienced significant dispositions of assets, both in sale transactions and as a result of our inability to maintain certain financial commitments. These dispositions of non-core assets have resulted in our development risks being concentrated in two primary projects in Australia and Colorado, which are both undeveloped and have minimal proved reserves associated with them. Should one or both of these projects prove to be economically infeasible, either due to market conditions or the absence of sufficient oil and/or natural gas discoveries, this could result in material adverse consequences to our operations and financial condition.

Our farm-out transactions with Falcon Oil & Gas, Ltd. ("Falcon") have created significant additional commitments for us and have reduced our operating flexibility.

On September 30, 2008, we closed the sale of a 50% working interest in four exploration permits in the Beetaloo Basin in Australia, covering our 7.0 million acre prospect in the Northern Territory in Australia to Falcon Oil & Gas Ltd., a related party. Although we remain the operator of this project, we are obligated to work with Falcon to reach joint decisions on all significant operating matters, many of which require substantial judgment. In addition, the transaction did not involve a carried interest and consequently, we are obligated to pay our proportionate share of the project's capital requirements immediately upon commencing our operating plan in 2009. There can be no assurance we will be successful in consistently reaching joint decisions with Falcon on all significant operating matters, including matters involving our respective economic obligations, or that the outcomes of these decisions will always be consistent with decisions we would have made solely on our own accord.

In addition, on November 10, 2008 we closed the sale of a 25% working interest in five wells in our 20,000 acre Buckskin Mesa Project area in Colorado to Falcon. The agreement also gives Falcon the option to acquire a 50%

working interest in the entire project. In addition, Falcon has the option to become the operator upon payment of additional consideration at the time the option is exercised.

The securities of Falcon received in the sale of a 50% working interest in four exploration permits in Australia are highly volatile and subject to significant changes in value due to significant changes in market value, and their value has substantial implications on our future liquidity.

Of the $25.0 million of total consideration in the Beetaloo Basin transaction, only $5.0 million was cash and $20.0 million was in the form of the common stock of Falcon which was initially delivered to us in the form of a special warrant, pending registration of the underlying shares. Falcon is a related party and is a publicly traded company on the Toronto Venture Exchange. Although the transaction provided 20% downside price protection, the value of the shares has fallen much further since the transaction was consummated due to global economic conditions and rapidly falling energy prices. Further, since the shares are traded on the Toronto Venture Exchange, they are priced in Canadian Dollars, and the strengthening of the U.S. Dollar in relation to the Canadian Dollar during the fourth quarter of 2008 has exacerbated the erosion of the market value of these securities.

The common stock of Falcon was ultimately delivered to us on January 5, 2009 and currently represents the substantial majority of current assets and our current liquidity, resulting in a concentration of risk. The shares are subject to significant market volatility, and as a result of our entering into a secured loan agreement with Falcon on October 1, 2008, they are now subject to significant restrictions. Accordingly, our inability to realize sufficient value from these securities and/or our inability to convert the securities into cash to fund our operations and development plans when needed, could present material adverse consequences to us.

Our secured note agreement with Falcon places multiple restrictions and requirements on us, some of which could result in adverse consequences to us.

The terms of the $5.0 million secured note agreement with Falcon, among other things, requires that we escrow a significant portion of the Falcon common stock received in the Beetaloo Basin transaction, maintain certain covenants, and pay interest currently until the note matures on April 30, 2009. As of December 31, 2008, the value of the Falcon shares pledged as collateral against the note is substantially less than the outstanding value on the note. The note is also secured by our five wells on the Buckskin Mesa property. In addition, one of Falcon's remedies in the event of our default is for us to relinquish operatorship on our Beetaloo Basin Project. Should we fail to perform on the note, or otherwise incur an event of Default, the pledged Falcon shares may be insufficient to fully satisfy the balance owed under the note, which could result in material adverse consequences to us.

We have entered into multiple amendments with the former lessee in relation to our Buckskin Mesa Project, which have resulted in a significant expansion in our drilling commitment obligations.

During the year ended September 30, 2008, we entered into several amendments with our assignor related to our property underlying our Buckskin Mesa Project. Although the most recent amendment we executed in September 2008 relieved us of several near term drilling commitments, our total drilling commitments increased substantially. These additional drilling commitments, along with other terms of the amendments, have increased our overall cash requirements. Should we be unable to meet these commitments on a timely basis, we could experience material adverse consequences, including the loss of a substantial portion of the leasehold for our Buckskin Mesa Project.

We are contingently liable to a third party for significant costs they have expended in relation to the development of a gas gathering system in Colorado.

We have entered into a Gas Gathering Agreement with CCES for a Phase I gas gathering system for our Buckskin Mesa Project. We also intend to reach agreement with CCES on a Phase II system, which will address our longer term gas gathering needs, sometime in 2009. Should we be unable to reach a mutual agreement with CCES on the Phase II system, we will be obligated to reimburse CCES for approximately $4.8 million of costs they have expended on the gathering system as of September 30, 2008. This contingent liability is increasing as work continues on the gathering system, and in the event we become liable to reimburse CCES for these costs, it could result in material adverse consequences to us.

The lack of production and established reserves for our properties impairs our ability to raise capital.

As of September 30, 2008, we have established very limited production of natural gas from a limited number of wells, and have had a limited number of properties for which reserves have been established, making it more difficult to raise the amount of capital needed to fully exploit the production potential of our properties. In addition, we have sold substantial assets during the year and subsequent to our fiscal year end, including our only revenue producing properties, which has substantially diminished our reserve base and increased our ongoing operating cash needs. These factors make it more likely we will have to raise capital on terms less favorable than we would desire, which may result in increased dilution to existing stockholders and high financing costs.

Two related parties control a significant percentage of our outstanding common stock, which may enable them to control many significant corporate actions and may prevent a change in control that would otherwise be beneficial to our stockholders.

Entities controlled by Marc A. Bruner and Christian Russenberger beneficially owned approximately 33.2% and 13.4%, respectively, of our common stock as of December 31, 2008. The control and/or significant influence held by such entities may have a substantial impact on matters requiring the vote of common shareholders, including the election of our directors and most of our corporate actions. Such control could delay, defer or prevent others from initiating a potential merger, takeover or other change in control that might benefit us and our shareholders. Such control could adversely affect the voting and other rights of our other shareholders and could depress the market price of our common stock.

Marc A. Bruner is the controlling owner of MAB Resources, LLC. Mr. Bruner serves as chairman of the board, chief executive officer and president of Falcon, a company whose stock is traded on the TSX Venture Exchange, and our partner in our primary exploration and development projects.

Christian Russenberger is the president of Global Project Finance AG, our most significant creditor.

Our convertible debentures could significantly dilute the interests of shareholders.

In November 2007, we issued convertible debentures in the aggregate principal amount of approximately $7.0 million. The debentures are convertible into shares of our common stock at any time prior to their maturity dates at a current conversion price of $0.15, subject to adjustments for stock splits, stock dividends, stock combinations and other similar transactions. The conversion prices of the convertible debentures could be further lowered, perhaps significantly, in the event of our issuance of common stock below the convertible debentures' conversion price, either directly or in connection with the issuance of securities that are convertible into, or exercisable for, shares of our common stock.

In addition, we issued five-year warrants to the holders of the convertible debentures. The warrant holders are entitled to purchase an aggregate of 46.4 million shares of our common stock at exercise prices ranging from $0.24 to $0.28 per share, inclusive of warrants issued in consideration of certain waivers and amendments during our fiscal year ended September 30, 2008. Both the number of warrants and the exercise price are subject to potential adjustments which could result in further dilution to our stockholders.

Neither the convertible debentures nor the warrants establish a "floor" that would limit reductions in the conversion price of the convertible debentures or the exercise price of the warrants that may occur under certain circumstances. Correspondingly, there is no "ceiling" on the number of shares that may be issuable under certain circumstances under the anti-dilution adjustment in the convertible debentures and warrants. Accordingly, our issuance of the convertible debentures and warrants could significantly dilute the interests of our shareholders.

Our failure to satisfy our registration, listing and other obligations with respect to the common stock underlying the warrants issued to our convertible debenture holders could result in adverse consequences, including acceleration of the convertible debentures.

We are required to file a registration statement, and to have it become effective, to cover the resale of the common stock underlying the warrants, until the earlier of the date the underlying common stock may be resold pursuant to

Rule 144 under the Securities Act of 1933 without any type of restriction or the date on which the sale of all of the underlying common stock is completed, subject to certain exceptions. We will be subject to various penalties for failing to meet our registration obligations, which include cash penalties and the forced redemption of the convertible debentures.

We are obligated to make significant periodic payments of interest under our credit facilities.

As of September 30, 2008, we have drawn down $39.8 million on our credit facility with Global Project Finance AG. Interest on the credit facility borrowings accrues at 6.75% over the prime rate and is payable quarterly. If the prime rate remains at 4.00% and we take no additional draws, our required interest payment will be $4.3 million during the 2009 fiscal year. As of September 30, 2008, we were in default of payments in the amount of $0.8 million, consisting of fees owed to the lender. All unpaid and accrued interest was converted into our common shares at September 30, 2008, totaling $6.5 million. The lender has waived and released us from any and all defaults, failures to perform, and any other failures to meet our obligations through October 1, 2009. If we default on our payment obligations in the future, the lender will have all rights available under the instrument, including acceleration, termination and enforcement of its security interest in our Buckskin Mesa Project in the Piceance Basin, Colorado.

The issuance of shares upon exercise of outstanding warrants and options may cause immediate and significant dilution to our existing stockholders.

As of September 30, 2008, we have issued warrants and options to purchase a total of 177.5 million shares of common stock. The issuance of shares upon exercise of warrants and options may result in significant dilution to the interests of our existing stockholders.

Our officers, directors and advisors are engaged in other businesses, which may result in conflicts of interest.

Certain of our officers, directors, and advisors also serve as directors of other companies or have significant shareholdings in other companies. To the extent that such other companies participate in ventures in which we may participate, or compete for prospects or financial resources with us, these officers and directors will have a conflict of interest in negotiating and concluding terms relating to the extent of such participation. In the event that such a conflict of interest arises at a meeting of the Board of Directors, a director who has such a conflict must disclose the nature and extent of his interest to the Board of Directors and abstain from voting for or against the approval of such participation or such terms.

We depend on a limited number of key personnel who would be difficult to replace.

We depend on the performance of our executive officers and other key employees. The loss of any member of our senior management or other key employees could negatively impact our ability to execute our strategy. We do not maintain key person life insurance policies on any of our employees.

Reserve estimates depend on many assumptions that may turn out to be inconclusive, subject to varying interpretations or inaccurate.

Estimates of natural gas and oil reserves are based upon various assumptions, including assumptions relating to natural gas and oil prices, drilling and operating expenses, capital expenditures, ownership and title, taxes and the availability of funds. The process of estimating natural gas and oil reserves is complex. It requires interpretations of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise. In addition, the global energy markets have experienced an extraordinary period of pricing volatility during the last six months of the 2008 calendar year. There can be no assurance that this pricing volatility will not continue into the future, or possibly worsen as the global economy experiences the current global recession.

Actual natural gas and oil prices, future production, revenues, operating expenses, taxes, development expenditures and quantities of recoverable natural gas will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of future net revenues at any time. A reduction in natural gas and oil prices, for example, would reduce the value of reserves and reduce the amount of natural gas and oil that could be economically produced, thereby reducing the quantity of reserves. At any time, there might be adjustments of estimates of reserves to reflect production history, results of exploration and development, prevailing natural gas prices and other factors, many of which are beyond our control.

Undeveloped reserves, by their nature, are less certain. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. Any reserve data assumes that we will make these capital expenditures necessary to develop our reserves. To the extent that we have prepared estimates of our natural gas and oil reserves and of the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the actual results will be as estimated.

Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, natural gas and oil prices, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce natural gas or oil from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of natural gas and oil-bearing structures or favorable stratigraphy, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable geoscientists to know whether hydrocarbons are, in fact, present in those structures. We are employing 2-D and 3-D seismic technology for certain of our projects. The use of 2-D and 3-D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and the profitability of our ventures may be adversely affected. Even with the use of advanced seismic applications, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline.

We often gather 2-D and 3-D seismic over large areas. Our interpretation of seismic data delineates those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data and, in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in a prospective area. If we are unable to lease those locations on acceptable terms, we will have made substantial expenditures to acquire and analyze 2-D and 3-D data without having an opportunity to attempt to benefit from those expenditures.

Substantially all of our oil and gas properties are located in the Rocky Mountains and in the Northern Territory in Australia, making us vulnerable to specific risks associated with operating in these geographic areas.

As the result of significant dispositions of assets during the year ended September 30, 2008, and the sale of our only producing gas wells in December, 2008, substantially all of our remaining oil and gas resources and operations are located in Buckskin Mesa, Colorado and the Northern Territory, Australia. As a result, we may be disproportionately exposed to the effect of delays or interruptions of production from these areas caused by significant governmental regulation, transportation capacity constraints, the availability and capacity of compression and gas processing facilities, curtailment of production or interruption of transportation of natural gas produced from the wells in these areas, as well as the remoteness and lack of infrastructure in the case of the Australian properties.

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Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in the Rocky Mountains and in Australia are adversely affected by seasonal weather conditions and lease stipulations designed to regulate land use, including operating guidelines for designated wildlife habitats and areas with scenic resource value. In certain areas in Australia and on federal lands in the U.S., drilling and other oil and natural gas activities can only be conducted during limited times of the year. This limits our ability to operate in those areas and can intensify competition during those times for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs, or cause us to fail to meet our drilling commitments on a timely basis.

Acquisitions are a part of our business strategy and are subject to the risks and uncertainties of evaluating recoverable reserves and potential liabilities. Properties that we buy may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them.

One of our growth strategies is to capitalize on opportunistic acquisitions of oil and natural gas reserves. The successful acquisition of producing and non-producing properties requires an assessment of a number of factors. These factors include recoverable reserves, future oil and gas prices, operating costs, potential environmental and other liabilities, title issues and other factors. Our reviews of acquired properties are inherently incomplete, because it generally is not feasible to perform an in depth review of every individual property involved in each acquisition. Ordinarily, we focus our review efforts on the higher value properties and sample the remainder. However, even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies or their potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. We sometimes knowingly assume certain environmental and other risks and liabilities in connection with acquired properties. It is possible that our future acquisition activity will result in disappointing results. We could be subject to significant liabilities related to acquisitions.

In addition, there is strong competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our strategy of completing acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to pursue our acquisition strategy may be hindered if we are unable to obtain financing or regulatory approvals.

Acquisitions often pose integration risks and difficulties. In connection with future acquisitions, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations. Possible future acquisitions could result in our incurring additional debt, contingent liabilities and expenses, all of which could have a material adverse effect on our financial condition and operating results.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

A portion of our business activities has been conducted through joint operating agreements under which we own partial interests in oil and natural gas properties. If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The failure of an operator of our wells to adequately perform operations or an operator’s breach of the applicable agreements could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others, therefore, depends upon a number of factors outside of our control, including the operator's deployment of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells and use of technology. Because we do not have a majority interest in certain wells we do not operate, we may not be in a position to remove the operator in the event of poor performance.

Market conditions or operation impediments may hinder our access to natural gas and oil markets or delay our production.

The marketability of our production depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. The dependence is heightened where the infrastructure is less developed. Therefore, if drilling results are positive in certain areas, a new gathering system may need to be built to handle the potential volume of gas produced. We might be required to shut in wells, at least temporarily, for lack of a market or because of the inadequacy or unavailability of transportation facilities. If that were to occur, we would be unable to realize revenue from those wells until arrangements were made to deliver production to the market.

Our ability to produce and market natural gas and oil is affected and also may be harmed by:

- the lack of pipeline transmission facilities or carrying capacity;
- government regulation of natural gas and oil production;
- government transportation, tax and energy policies;
- changes in supply and demand; and
- general economic conditions.

We may incur additional debt in order to fund our exploration and development activities, which would continue to reduce our financial flexibility and could have a material adverse effect on our business, financial condition or results of operations.

If we incur indebtedness, our ability to meet our debt obligations and reduce our level of indebtedness will depend on future performance. General economic conditions, oil and gas prices and financial, business and other factors affect our operations and future performance; many of these factors are beyond our control. We cannot assure you that we will be able to generate sufficient cash flow to pay the interest on our debt or that future working capital, borrowings or equity financing will be available to pay for or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and performance at the time we need capital. We cannot assure you that we will have sufficient funds to make our debt payments. Lack of sufficient funds and/or the inability to negotiate new borrowing terms may cause us to sell significant assets which could have a material adverse effect on our business and financial results.

We have found material weaknesses in our internal controls that require remediation and concluded that our internal controls over financial reporting at September 30, 2008, were not effective.

As we discuss in Part II, Item 9A(T), “Controls and Procedures”, of this Form 10-K, we have determined that we continue to have deficiencies, including material weaknesses, in our internal control over financial reporting as of September 30, 2008. In addition, we have discovered material errors in our Form 10-Q filings during 2008 and 2007, requiring us to restate those filings.

Although we are fully committed to remediating our material weaknesses, and we believe we have made progress in making sustainable improvements in our internal controls, we have not completed our remediation efforts in relation to the design and testing of our internal controls, and further remediation may be required.

While we are taking immediate steps and dedicating substantial resources to correct these material weaknesses, they will not be considered fully remediated until the new and improved internal controls operate for a period of time, are tested and are found to be operating effectively.

Our remediation efforts may not be sufficient to maintain effective internal controls in the future. We may not be able to implement and maintain adequate controls over our financial processes and reporting, which may require us to restate our financial statements again in the future. In addition, we may discover additional material weaknesses or significant deficiencies in our financial reporting system in the future. Any failure to implement new controls, or difficulty encountered in their implementation, could cause us to fail to meet our reporting obligations or result in material misstatements in our financial statements. Inferior internal controls could also cause investors to lose confidence in our reported financial information, which could result in a lower trading price of our common shares.

Pending the successful implementation and testing of new controls, we will continue to perform mitigating procedures. If we fail to remediate our material weaknesses, we could be unable to provide timely and reliable financial information, which could have a material adverse effect on our business, results of operations or financial condition.

We have significant future capital requirements. If these obligations are not met, our growth and operations could be limited or suspended indefinitely.

Our future growth depends on our ability to cause the development of the working interests we have acquired, and such development will require the expenditure of significant capital either by us or by third parties through additional farm-out agreements. In addition, we may acquire interests in additional oil and gas leases where we will be required to pay for a specific amount of the initial costs and expenses related to the development of those leases. We intend to finance our foreseeable capital expenditures through additional farm-out agreements, private placements of debt or equity, and additional funding for which we have no commitments at this time. Future cash flow and the availability of financing will be subject to a number of variables such as; the success of exploration and development on our leases, success in locating and producing reserves, and the prices of natural gas and oil.

Additional financing sources will be required in the future to fund developmental and exploratory drilling. Issuing equity securities to satisfy our financing requirements could cause substantial dilution to our existing stockholders. Additional debt financing could lead to a substantial portion of operating cash flow being dedicated to the payment of principal and interest, the Company being more vulnerable to competitive pressures and economic downturns and restrictions on our operations.

Financing may not be available in the future, or we might not be able to obtain necessary financing on acceptable terms, if at all. If sufficient capital resources are not available, we might be forced to curtail drilling and other activities or be forced to sell assets on an unfavorable basis, which would have an adverse effect on our business, financial condition and results of operations.

Our leases and/or future properties might not produce as anticipated, and we might not be able to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them, which could cause us to incur losses.

Although we have reviewed and evaluated our leases in a manner consistent with standard industry practices, our review and evaluation may not reveal all existing or potential problems. These same factors apply to future acquisitions to be made by us. We may not perform inspections on every well, and environmental issues may not be observable during an inspection. When problems are identified, a seller may be unwilling or unable to provide effective contractual protection against those problems, and we may assume environmental and other risks and liabilities in connection with the acquired properties.

We do not plan to insure against all potential operating risks. We might incur substantial losses and be subject to substantial liability claims as a result of our natural gas and oil operations.

We do not intend to insure against all risks. We intend to maintain insurance against various losses and liabilities arising from operations in accordance with customary industry practices and in amounts that management believes to be prudent. Losses and liabilities arising from uninsured and underinsured events or in amounts in excess of existing insurance coverage could have a material adverse effect on our business, financial condition or results of operations. Our natural gas and oil exploration and production activities are subject to hazards and risks associated with drilling for, producing and transporting natural gas and oil, and any of these risks can cause substantial losses resulting from:

- environmental hazards, such as uncontrollable flows of natural gas, oil, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;

- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death;
- regulatory investigations and penalties; and
- natural disasters.

Any of these hazards could have a material adverse effect on our ability to conduct operations and may result in substantial losses. We may elect not to obtain insurance in the event that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could have a material adverse effect on our business, financial condition and results of operations.

We are subject to various risks associated with our international operations.

A significant portion of our remaining assets are in Australia, which subjects us to various risks associated with doing business in a foreign country. These risks include, among other things:

- governmental and regulatory requirements unique to the country;
- exposure to foreign currency losses;
- foreign taxation requirements, which can differ significantly from U.S. regulations;
- local economic and/or political instability; and
- potential difficulties in our ability to expatriate cash and/or assets to the U.S.

The incurrence of these kinds of circumstances are principally beyond our control, and could result in material adverse consequences to us.

Risks Relating to the Oil and Gas Industry

A substantial or extended decline in natural gas and oil prices may adversely affect our ability to meet our capital expenditure obligations and financial commitments.

Our revenues, operating results and future rate of growth are substantially dependent upon the prevailing prices of, and demand for, natural gas and oil. Declines in the prices of, or demand for, natural gas and oil may adversely affect our financial condition, liquidity, ability to finance planned capital expenditures and results of operations. Lower natural gas and oil prices may also reduce the amount of natural gas and oil that we can produce economically. During the last six months of the 2008 calendar year, natural gas and oil prices and markets have experienced extraordinary volatility, and they are likely to continue to be volatile in the future. A decrease in natural gas or oil prices will not only reduce revenues and profits, but will also reduce the quantities of reserves that are commercially recoverable and may result in charges to earnings for impairment in the value of assets. If natural gas or oil prices decline significantly for extended periods of time in the future, we might not be able to generate enough cash flow from operations to meet our obligations and make planned capital expenditures. Natural gas and oil prices are subject to wide fluctuations in response to relatively minor changes in the supply of, and demand for, natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control. Among the factors that could cause this fluctuation are:

- changes in supply and demand for natural gas and oil;
- general global economic conditions, and regional economic conditions in the U.S. and Australia;
- levels of production and other activities of the Organization of Petroleum Exporting Countries, or OPEC, and other natural gas and oil producing nations;
- market expectations about future prices;
- the level of global natural gas and oil exploration, production activity and inventories;

- political conditions, including embargoes, in or affecting other oil producing activity; and
- the price and availability of alternative fuels.

Lower natural gas and oil prices may not only decrease our revenues on a per unit basis, but also may reduce the amount of natural gas and oil that we are able to produce economically. A substantial or extended decline in oil or natural gas prices may materially and adversely affect our business, financial condition and results of operations.

Drilling for and producing natural gas and oil are high-risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future success depends on the success of our exploration, development and production activities. Such activities are subject to numerous risks beyond our control, including the risk that we will not find commercially productive natural gas or oil reservoirs. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretation. The cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or prevent drilling operations, including:

- unexpected drilling conditions;
- pressure or irregularities in geological formations;
- equipment failures or accidents;
- pipeline and processing interruptions or unavailability;
- title problems;
- adverse weather conditions;
- lack of market demand for natural gas and oil;
- delays imposed by or resulting from compliance with environmental and other regulatory requirements;
- shortages of or delays in the availability of drilling rigs and the delivery of equipment; and
- reductions in natural gas and oil prices.

Our future drilling activities might not be successful, and the drilling success rate overall or within a particular area could decline. We could incur losses by drilling unproductive wells. Although we have identified numerous potential drilling locations, we cannot be sure that we will ever drill them or will produce natural gas or oil from them or from any other potential drilling locations. Shut-in wells, curtailed production and other production interruptions may negatively impact our business and result in decreased revenues.

Competition in the oil and gas industry is intense, and many of our competitors have greater financial, technological and other resources than we do, which may adversely affect our ability to compete.

We operate in the highly competitive areas of oil and gas exploration, development and acquisition with a substantial number of other companies. We face intense competition from independent, technology-driven companies as well as from both major and other independent oil and gas companies in each of the following areas:

- seeking oil and gas exploration licenses and production licenses;
- acquiring desirable producing properties or new leases for future exploration;
- marketing natural gas and oil production;
- integrating new technologies;
- acquiring the equipment and expertise necessary to develop and operate properties; and
- hiring and retaining a staff of competent technical and administrative professionals.

Many of our competitors have substantially greater financial, managerial, technological and other resources. These companies might be able to pay more for exploratory prospects and productive oil and gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. To the extent competitors are able to pay more for properties than we are able to afford, we will be at a competitive disadvantage. Further, many competitors may enjoy technological advantages and may be able to implement new technologies more rapidly. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, implement advanced technologies, evaluate and select suitable properties and consummate transactions in this highly competitive environment.

Shortages of rigs, equipment, supplies and personnel could delay or otherwise adversely affect our cost of operations or our ability to operate according to our business plan.

In periods of increased drilling activity, shortages of drilling and completion rigs, field equipment and qualified personnel could develop. From time to time, these costs have sharply increased in various areas around the world and could do so again. The demand for and wage rates of qualified drilling rig crews generally rise in response to the increasing number of active rigs in service and could increase sharply in the event of a shortage. Shortages of drilling and completion rigs, field equipment or qualified personnel could delay, restrict or curtail our exploration and development operations, which could in turn harm our operating results.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Because total estimated proved reserves include our proved undeveloped reserves at September 30, 2008, production will decline even if those proved undeveloped reserves are developed and the wells produce as expected. The rate of decline will change if production from our existing wells declines in a different manner than we have estimated. The rate of decline may change under other circumstances as well. As a result, our future oil and natural gas reserves, and our production are highly dependent upon our success in efficiently developing and exploiting our current reserves. In addition, our potential oil and gas revenues and production depend on us finding or acquiring additional recoverable reserves economically. Our cash flow and results of operations are also dependent upon these factors. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs.

Assets may be impaired due to full cost accounting rules.

Under full cost accounting rules, capitalized costs of proved oil and gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%. Application of the “Ceiling Test” generally requires pricing future revenue at the unescalated prices in effect as of the end of each fiscal quarter and requires an impairment charge for accounting purposes if the ceiling is exceeded. While an impairment does not impact cash flow from operating activities, it still results in a charge to earnings. Once incurred, an impairment of oil and gas properties is not reversible at a later date. As with any charge to earnings, the market price for our stock may decline as a result.

Our industry is heavily regulated which increases our cost of doing business and decreases our profitability.

U.S. and Australian federal, state and local authorities regulate the oil and gas industry. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may affect, among other things, the pricing or marketing of oil and gas production. State and local authorities regulate various aspects of oil and gas drilling and production activities, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of oil and gas properties, environmental matters, safety standards, the sharing of markets, production limitations, plugging and abandonment and restoration of wells. The overall regulatory burden on the industry increases the cost of doing business, which, in turn, decreases profitability.

Our operations must comply with complex environmental regulations that may have a material adverse effect on our business.

Our operations are subject to complex and constantly changing environmental laws and regulations adopted by federal, state and local governmental authorities, including in the U.S. and in Australia. New laws or regulations, or changes to current requirements, could have a material adverse effect on our business. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. We would face significant liabilities to the government or other third parties for discharges of oil, natural gas, produced water or other pollutants into the air, soil or water, and we would have to spend substantial amounts on investigations, litigation and remediation if such a spill were to occur. We cannot be sure that existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced or altered in the future, will not have a material adverse effect on our results of operations and financial condition.

Risks Related to Our Common Stock

Our stock price and trading volume may be volatile, which could result in losses for our stockholders.

The equity trading markets periodically experience periods of volatility, which could result in highly variable and unpredictable pricing of equity securities. The market price of our common stock could change in ways that may or may not be related to our business, our industry or our operating performance and financial condition. In addition, the trading volume in our common stock may fluctuate and cause significant price fluctuations. Some of the factors that could negatively affect our share price or result in fluctuations in the price or trading volume of our common stock include:

- actual or anticipated quarterly variations in our operating results;
- actual or anticipated changes in our liquidity, financial position, or capital resources;
- changes in expectations as to our future financial performance or changes in financial estimates, if any, of public market analysts;
- announcements relating to our business or the business of our competitors;
- conditions generally affecting the oil and natural gas industry;
- changes in investor perceptions of the level of risk and volatility associated with investments in the oil and natural gas industry;
- the success of our operating strategy;
- the operating and stock price performance of other comparable companies; and
- the market price of our common stock.

The market price of our common stock has declined substantially during recent months, and as a result of these factors, it is possible that the market price of our common stock will remain volatile or decline even further in the future. In addition, many brokerage firms may not effect transactions and may not deal with low priced securities as it may not be economical for them to do so. This could have an adverse effect on developing and sustaining a market for our securities. In addition, an investor may be unable to use our securities as collateral.

Our common stock may not meet the criteria necessary to qualify for listing on one or more particular stock exchanges on which we seek or desire a listing. Even if our common stock does meet the criteria, it is possible that our common stock will not be accepted for listing on any of these exchanges.

Our common stock may be thinly traded, and therefore, an investor may not be able to easily liquidate his or her investment.

Although our common stock is currently traded on the OTC Bulletin Board, at any time, it may be thinly traded. To the extent that is true, an investor may not be able to liquidate his or her investment without a significant decrease in price, or at all.

We have not and do not anticipate paying dividends on our common stock.

We have not paid cash dividends to date with respect to our common stock. We do not anticipate paying dividends on our common stock in the foreseeable future since we will use all of our available cash to finance exploration and development of our properties. We are authorized to issue preferred stock and may pay dividends on our preferred stock issued in the future.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not Required by Form 10-K for Smaller Reporting Companies.

ITEM 2. DESCRIPTION OF PROPERTY

Location and Characteristics

Our headquarters are located at 1600 Stout Street Suite 2000 Denver, Colorado, 80202. The lease for this office space of approximately 12,400 square feet has a term expiring February, 2013. The annual rent is approximately $0.2 million with certain adjustments for inflation and expenses.

Currently, we own property in Colorado, where we have drilled five wells on our Buckskin Mesa property, and Australia, where we have drilled one well on our property in the Northern Territory, and in Montana, where we hold a land position in the Bear Creek area. The wells on these properties have not yet commenced oil and gas production. As of September 30, 2008, we owned working interests in eight additional natural gas wells in Colorado which are operated by EnCana Oil & Gas USA (“EnCana”). These interests were sold to a third party in December 2008. In November 2007, we sold 66,000 net acres of land and two wells in Montana and 173,738 acres of land in Utah and on May 30, 2008, we sold 605 net acres, 16 wells which had been drilled but not completed or connected to a pipeline, and rights to participate in an additional 8 wells in the Southern Piceance Basin in Colorado.

Piceance Basin, Colorado Properties

Buckskin Mesa Project. We own approximately 20,000 net acres of leasehold in Rio Blanco County, Colorado, subject to certain payment and work commitments, including five wells that were drilled (but not completed) during 2006-2007 calendar years, and six shut-in gas wells drilled by our predecessor in interest. During this fiscal year, we expanded our operational infrastructure for the project area, and spud and drilled the fifth of the five obligation exploratory wells specified in the original acquisition agreement with Daniels Petroleum Company (“DPC”), as amended (the “DPC Agreement”). Each of the five wells encountered greater than five hundred feet of net pay within the Cretaceous Mesa Verde Group, and each was cased in preparation for testing and completion. In conjunction with Clear Creek Energy Services, we continued working on the design and development of an expandable gathering system and primary production facility to allow for the handling and movement of a minimum of 15 million cubic feet of gas per day.

As of September 30, 2008, we had drilled five wells, awaiting completion and installation of the gathering system. At the end of the first calendar quarter of 2008, we extended and subsequently paid $0.5 million in penalties for three wells that were required to be drilled that quarter by agreeing to pay the $1.5 million fee, plus a $1.0 million additional payment as consideration for the extension. These amounts were paid on April 28, 2008, thereby reducing the total number of wells we were committed to drill for the remainder of calendar year 2008 to 13. Prior to June 30, 2008 (the due date for commencing the next four wells), we determined that we could not obtain the materials necessary to commence such operations by June 30, and we provided written notice of such force majeure condition to DPC. We were otherwise prepared to comply with all obligations regarding the referenced commitment. DPC objected to the notice. On June 30, 2008, we filed an action in Denver District Court requesting the court to issue a declaratory judgment concerning this dispute (the "Daniels Litigation"). On September 10, 2008, we entered into an amendment to the original agreement with DPC (the "Amendment"), which included a settlement of the Daniels Litigation. Under the Amendment, we paid $0.5 million for each of the four wells scheduled to be drilled by June 30, 2008, and we paid an additional $1.5 million on January 9, 2009, as required under the Amendment. Further, we are required to drill four wells by July 31, 2009, five additional wells by December 31, 2009, and eleven additional wells by December 31, 2010. If we do not satisfy these drilling requirements, our agreement with DPC requires that we pay DPC $0.5 million for each undrilled well on the last day of the applicable period.

As part of the settlement of the Daniels Litigation, PetroHunter and Daniels agreed to extend the date for commencing the first well in Buckskin Mesa to July 31, 2009, and to increase the total minimum number of obligation wells to 20, through December 2010. PetroHunter and Falcon closed the first phase of their agreement (announced August 25, 2008) on November 10, 2008, under which PetroHunter has begun testing and completion operations on two of the five wells, which PetroHunter previously drilled but did not complete in Buckskin Mesa.

PetroHunter is moving forward on the Buckskin Mesa gas gathering system. Under PetroHunter's agreement with CCES Piceance Partners I, LLC ("Clear Creek"), PetroHunter and Clear Creek have begun ordering all necessary materials for construction of the Buckskin Mesa gathering facilities.

Logs from the five wells which PetroHunter drilled in this area in 2007 indicate an average of 500 to 600 feet of pay. The primary objective in these wells is the Williams Fork formation, while the secondary objectives are the Sego, Cozzette, and Corcoran formations, members of the Iles formation, which are below the Williams Fork.

The Company recently initiated fracture stimulation operations on the Lake 16-21 and Lake 6-22 wells. Flow testing operations are continuing and have recovered hydrocarbons from both wells. PetroHunter will continue its completion and testing program on the Lake 16-21 and Lake 6-22 wells in the remaining intervals over the first and second quarters of our next fiscal year.

Piceance II Project. As of September 30, 2008, we owned interests within the Piceance II Project area in one undeveloped lease and an undivided 50% working interest in eight producing wells operated by EnCana Oil & Gas (USA), Inc. ("EnCana"), all in Garfield County, Colorado, and which were sold to a third party on December 30, 2008.

Effective October 1, 2007, we entered into a trade by which we exchanged our 40 net acre leasehold interest in certain lands located in Sections 16, 17, 20 and 21 of Township 7 South, Range 95 West (along with 0.35 net under 19 gross wells) for 40 net acres of leasehold covering the 40 acre parcel located in Section 22 of Township 7 South, Range 95 West adjacent to the Furr leased lands (along with two net under two gross wells). The trade also included our acquisition of a new lease dated December 10, 2007, covering the remaining 50% of the balance of the lands located in said Section 22 to which 10 of the 14 Furr area wells were attributable.

On May 30, 2008, we completed the sale of 605 net acres of land, 16 wells which had been drilled but not completed or connected to a pipeline and rights to participate in an additional 8 wells to Laramie Energy II, LLC. Additionally, as of June 30, 2008, as part of this transaction, we held $0.8 million in escrow relating to a dispute between us and the lessor of 435 acres of land in the Southern Piceance in which the lessor of this land claims that the lease will be terminated in conjunction with the Laramie transaction. On August 1, 2008, we transferred the $0.8 million in escrow back to Laramie and retained the 435 acres of land relating to the escrowed amount.

Plan of Operations. In fiscal 2009, we will focus on completing the five wells drilled in 2006-2007, and connect them to the gathering system, followed by drilling nine additional obligation wells, which must be commenced by December 31, 2009. Completion of the gathering system and central facility for the Buckskin Mesa Project will also enable us to recomplete and hook-up one or more of the six additional shut-in gas wells acquired with the properties in 2006.

Extensive regulatory compliance work has been initiated to facilitate our asset development plan, and some title issues are being addressed in connection with the drilling program for the fiscal year 2009. In summary, execution of the plan for these assets will optimally yield the drilling of not less than nine new exploratory wells in the Buckskin Mesa

Prospect, and the completion or recompletion of as many as six wells in the Buckskin Mesa Prospect during fiscal year 2009.

Australia Properties
Beetaloo Basin Project. The Beetaloo Basin property in the Northern Territory of Australia currently consists of approximately 7.0 million net contiguous acres. Sweetpea now owns an undivided 50% working interest in the existing four exploration permits that cover this acreage following the sale of the other undivided 50% working interest to Falcon Oil & Gas Australia, Ltd., effective September 30, 2008.

Located about 600 kilometers south of Darwin, the Beetaloo Basin is a large basin, comparable in size to the Williston Basin in the U.S. or the entire southern North Sea basin. Structurally it has been viewed as a relatively simple intracratonic, passive margin basin, with minor extension (strike-slip), filled with sediments ranging from Cambrian to Mesoproterozoic rocks. However, interpretation of 2-D seismic data acquired by us in 2006 requires modification of the structural and tectonic history of the basin. The broad, low relief structures previously recognized in the basin, probably related to strike-slip movement, represent only a portion of its history. Significant and possibly multiple compressional events are observed in the basin. Ongoing geophysical evaluation has identified a more recent compressional history along the western margin of the basin resulting in a series of westerly verging, imbricate thrust faults. All identified structures are untested and prospective.

The basin has many thousands of meters of sediments, but the reservoirs of interest to us are within 4,000 meters of the surface, most less than 3,000 meters. The sedimentary rocks include thick (hundreds of meters), rich source rocks, namely the Velkerri Shale with Total Organic Carbon ("TOC") contents as high as 12% and the Kyalla Shale with typical TOC contents of 2-3%. There are also a number of sandstone reservoirs interbedded with the rich source rocks. These formations, from stratigraphically youngest to oldest, include the Cambrian Bukalara Sandstone, and the Neoproterozoic Hayfield, Jamison, Moroak, and Bessie Creek sandstones. A number of even deeper sandstones are expected to be very tight and are viewed as not prospective in the single well where they were tested east of the Basin.

Three primary plays have been recognized within the basin. The first is a conventional structural, shallow sweet oil play of 35° API gravity. The Bukalara, Hayfield, Jamison, and Moroak sands (and perhaps the Bessie Creek sand along the western margin) have potential for oil and gas accumulations in trapped and sealed geometries. Most of the eleven previous wells drilled within the basin had oil and gas shows, and the Jamison No. 1 well tested oil on a Drill Stem Test. Detailed petrophysical analyses have been performed on all wells and have identified significant potential in some of these tests.

The second play is an unconventional fractured shale play within the Kyalla and Velkerri formations, not unlike the Barnett Shale play in Texas, although the Barnett Shale is of Paleozoic age and the Velkerri is older, being of the Proterozoic age. It is unknown whether the hydrocarbons will be gas or oil (or possibly both) for this exploration target; however, the Barnett Shale model and algorithms in our petrophysical analyses of these shales suggest they are viable targets. The Barnett Shale is a Paleozoic (Mississippian) black shale in Texas that ranges from a few feet to over 1,000 feet but is generally considered most favorable where the Barnett is 300 feet or more and is thermally mature with vitrinite reflectance values greater than 1.1% (Ro≥1.1) 400 feet thick and has TOC of between 1-5 weight percentage averaging between 2.5% and 3.5%. Barnett wells are typically stimulated to induce fracturing or enhance fracturing. The Barnett where it is the thermal maturity window of a vitrinite reflectance of 1.1 or above is considered to be in the gas window and thus prospective. The Velkerri Shale in the Beetaloo Basin is up to 2438 feet (800 meters) thick, but the prospective portion of the Velkerri where TOCs range from 4 to 12% commonly in the 4-7% range in a 140 meter interval (or about 425 feet). The Velkerri Shale which is PreCambrian (approximately 1.4 billion years old) is in the gas window throughout much of the Beetaloo Basin with equivalent thermal maturity values of 1.1 or higher. It should be noted that a geochemical equivalency was developed to allow comparison of the thermal maturity levels to standard vitrinite reflectance levels. Thus, the Velkerri and Barnett are analogous in thickness, thermal maturity where prospective for gas, and TOC. The Kyalla Shale is also PreCambrian (Proterozoic) in age and can reach thicknesses in the subsurface up to 800 meters in the Beetaloo Basin. Approximately 115 meters (350 feet) of prospective interval for both oil and gas although TOC is somewhat lower ranging from about 1.5-8% although mostly in the 2-4% range. The upper part of the Kyalla is in the oil window (greater than .7% equivalent vitrinite reflectance) and the lower part of the Kyalla is in the gas window (greater than 1.1% equivalent vitrinite reflectance. Both Kyalla and Velkerri shales are fractured as evidenced cores taken in wells in the basin and observed on well logs. For example, a Formation Micro Imager Log in the Kyalla demonstrates considerable fracturing and this fracturing extends throughout most horizons encountered in a recent test, the Shenandoah #1 complete with hydrocarbon (both oil and gas) shows. For these reasons we consider the Kyalla and Velkerri Shales to be analogous to the Barnett Shale.

Finally, the Moroak and Bessie Creek sandstones offer a Basin Centered Gas Accumulation (BCGA) play at the center of the basin. It is an unconventional resource play characterized by a lack of a gas/water contact. Petrophysical analyses of several wells previously drilled in the basin demonstrate the presence of a BCGA in the basin.

We spudded the Sweetpea Shenandoah No. 1 well on July 31, 2007 and drilled to 4,724 feet. Intermediate casing was run on September 15, 2007 and the well was then suspended with an intention to deepen the well to a depth of 9,580 feet.

Because of its proximity and geological similarity to the Balmain No. 1 well, we regard this well as a twin to the Balmain No. 1 well that was drilled by an unrelated third party in 1992. The original plan to drill the Shenandoah No. 1 well under-balanced with air was modified due to encountering a shallow-sand formation that produced excessive water. The well was drilled with air along with water and mud. Oil and gas hydrocarbon shows in the Hayfield Formation and Kyalla Shale were confirmed. The mudlog exhibits gas shows and fluorescence starting at about 1,900 feet, in the Hayfield Formation, and continuing through to present depth of 4,550 feet. Over 700 feet of hydrocarbon shows have been encountered. Geologically, the Shenandoah No. 1 well has matched its prognosis and the drilling results correlate with the Balmain No. 1 well. In 2008, the Company engaged NuTech Energy Alliance to further analyze the logs from the Well, and to run a shale model, using recent North American oil productive fractured shale analogs. The preliminary results of the NuTech analysis for shales at approximately 3,000-foot depth indicate an estimated initial production rate of several hundred barrels a day (assuming a horizontal well), and a 3-year recovery of 70,000 barrels per well.

To date, seven drilling locations have been identified based on extensive geological and geophysical analysis. These locations have been cleared through the Northern Land Council, responsible for consulting with and representing traditional landowners and other Aborigines with an interest in land. Final drilling approval was received in May 2007, and these locations have been staked and will be formally surveyed. The preparation of drilling pads and access lines commenced the last week of May 2007 and continued into June 2007. We are attempting to obtain drilling locations beyond the initial seven locations.

From July through November of 2006, 686 kilometers of new 2-D seismic data were acquired throughout the Beetaloo Basin. Additionally, 1,000 kilometers of previously acquired 2-D seismic data were reprocessed. Along, with the other existing 1,500 kilometers of 2-D seismic data that have not been reprocessed, geologic structure maps were generated for the basin.

The exploration drilling program for fiscal 2009 will test several play concepts within the basin. Hydrocarbon potential exists in shallow, conventional structures (in the form of oil), and in deeper unconventional reservoirs, including fractured shales and basin centered gas accumulations. The unconventional plays may be gas and/or oil. All of the exploration wells are planned to reach a total depth in the Bessie Creek Sandstone formation. The deepest penetration is expected to be 3,000 meters.

Northwest Shelf Project. Effective February 19, 2007, the Commonwealth of Australia granted to Sweetpea an exploration permit in the shallow, offshore waters of Western Australia. The permit, WA-393-P, has a six-year term and encompasses almost 20,000 acres. Geophysical data across the permit from public sources has been acquired and has been analyzed. We have committed to an exploration program with geological and geophysical data acquisition in the first two years with a third year drilling commitment and additional wells to be drilled in the subsequent three year period depending upon the results of the initial well.

Plan of Operations. In Australia, we plan to explore and develop portions of our undivided 50% working interest in the four exploration permits that comprise the 7.0 million net acres of the project area in the Northern Territory of Australia (Beetaloo Basin). We plan to resume drilling of the Shenandoah No. 1 well. We are currently committed to drill eight additional wells on our four permits and complete a potential delineation seismic program, projected to cost a minimum of $37.0 million ($18.5 million for our 50% working interest). In calendar year 2009, we may farm-out a portion of our working interest in the acreage to third parties.

Other Assets

Bear Creek, Montana. On September 30, 2008, we owned slightly greater than 15,990 net acres of leasehold in a combination deeper conventional gas/coalbed methane project area located in southern Montana, east of the Fiddler Creek heavy oil assets. The primary deep objectives are incised Greybull valley-fill sequences along the Nye-Bowler lineament, and the Frontier sandstone, while the shallow Ft. Union provides an opportunity to produce methane from multiple thin coal lenses at intervals from 500 to 3,000 feet. No activity was conducted in this project area during the fiscal year, nor are any funds budgeted to evaluation of this asset in the coming year.

Oil and Gas Reserves

The following table sets forth the Company's quantities of domestic proved reserves, for the years ended September 30, 2008, and 2007 as estimated by independent petroleum engineers Gustavson Associates, LLC. The table summarizes our domestic proved reserves, the estimated future net revenues from these reserves and the standardized measure of discounted future net cash flows attributable thereto at September 30, 2008 and 2007. In accordance with PetroHunter's planning and budgeting cycle, proved undeveloped reserves included in this table include only economic locations that are forecast to be on production before October 1, 2013. As of September 30, 2008, proved undeveloped reserves represent 83.24% of our total proved reserves. In December 2008, we sold our working interest in our proved developed reserves to a third party for $2.3 million.

The following table is a summary of our oil and gas reserves (in thousands, except per unit data):

	Years Ended September 30, 2008		Years Ended September 30, 2007	
Proved Undeveloped Reserves				
Natural gas (MMcf)		16,504		13,699
Oil (MBbl)		5		19
Proved Developed Reserves				
Natural gas (MMcf)		3,310		—
Oil (MBbl)		2		112
Total Proved Reserves (MMcfe)		19,858		14,486
Estimated future net cash flows, before income tax	$	33,739	$	44,956
Standardized measure of discounted future net cash flows, before income taxes	$	8,357	$	19,865
Future income tax		—		—
Standardized measure of discounted future net cash flows, after income taxes	$	8,357	$	19,865
Calculated weighted average price at September 30,				
Gas ($/Mcf)	$	3.36	$	3.47
Oil ($/Bbl)	$	79.47	$	61.28

Production Volumes, Average Sales Prices and Average Production Costs

The following table sets forth certain information regarding our net production of oil and natural gas, and certain price and cost information for our fiscal years ended September 30, 2008, 2007 and 2006.

	For the fiscal year ended September 30, 2008		2007		2006	
Production Data:						
Natural gas (Mcf)		286,474		456,740		5,822
Oil (Bbl)		348		137		—
Average Prices:						
Natural gas (per Mcf)	$	6.82	$	6.16	$	6.12
Oil (per Bbl)	$	111.80	$	52.40	$	—

Production Costs:						
Lease operating expenses (per Mcfe)	$	2.79	$	1.73	$	0.63

(a) 2008 lease operating expense includes monthly compressor rental of $0.1 million
(b) All information relates to the US operations as no drilling or production occurred in Australia during 2008.

Productive Wells

The following table summarizes information at September 30, 2008, relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of production, but specifically exclude wells drilled and cased during the fiscal year that have yet to be tested for completion. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests in the gross wells.

	Gross			Net		
	Oil	Gas	Total	Oil	Gas	Total
Location						
Colorado	—	10	10	—	6	6
Australia	—	—	—	—	—	—
Total	—	10	10	—	6	6

Oil and Gas Drilling Activities

During the fiscal year ended September 30, 2008, our drilling activities were limited to Colorado and Australia. We drilled, or participated in the drilling of a total of 2 gross wells and 2 net wells categorized as follows: the Lake 6-22 well in the Buckskin Mesa Project, and the Shenandoah #1 well in the Beetaloo Basin Project. During 2008, we drilled no dry exploratory wells and no development wells.

During the fiscal year ended September 30, 2007, our drilling activities were limited to Colorado and Australia. We drilled, or participated in the drilling of a total of 39 gross wells and 14.46 net wells categorized as follows: (i) 2.21 net wells under 21 gross wells drilled, completed and turned down-line to production; and (ii) 12.25 net wells under 18 gross wells drilled and cased, but not completed for production. In addition, the Company acquired during the year six net under six gross producing wells in Colorado that are shut-in awaiting a tie-in to the market, and drilled one net under one gross exploratory well in Australia that is currently suspended. During 2007, we drilled no dry exploratory wells and no development wells.

During the fiscal year ended September 30, 2006, our drilling activities were limited to Colorado; we drilled, or participated in the drilling of six gross exploratory wells and 2.14 net exploratory wells with no dry exploratory wells, and we acquired two gross and net oil wells. We did not drill development wells during 2006.

Oil and Gas Interests

As of September 30, 2008, we owned interests in the following developed and undeveloped acreage positions. Undeveloped acreage refers to acreage that has not been placed in producing units.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Location				
Colorado	400	240	24,833	20,174
Montana	—	—	18,147	15,991
Australia	—	—	7,000,000	3,500,000
Total	400	240	7,042,980	3,536,165

Impairment of Oil and Gas Properties

Costs capitalized for properties accounted for under the full cost method of accounting are subjected to a ceiling test limitation to the amount of costs included in the cost pool by geographic cost center. Costs of oil and gas properties may not exceed the ceiling which is an amount equal to the present value, discounted at 10%, of the estimated future net cash flows from proved oil and gas reserves plus the cost, or estimated fair market value, if lower, of unproved properties. Should capitalized costs exceed this ceiling, an impairment is recognized. During 2007, we recorded an impairment expense in the amount of $24.1 million, representing the excess of capitalized costs over the ceiling, as calculated in accordance with these full cost rules. During 2008 we recorded an impairment of $30.8 million. Current year impairment was due to decreases in natural gas prices from our third quarter ended June 30, 2008 of $10.51 per Mcf, to $4.96 per Mcf as of September 30, 2008.

Depreciation, Depletion, Amortization and Accretion

Depreciation, depletion, amortization and accretion expense (“DD&A”) was $1.2 million in 2008 and $1.2 million in 2007.

ITEM 3. LEGAL PROCEEDINGS

As of September 30, 2008, the Company is not a party to any legal or administrative actions or proceedings.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information

Our common stock commenced trading on the OTC bulletin board on April 20, 2005, under the symbol “DGEO,” and has been trading under the symbol “PHUN” since August 21, 2006. The following table sets forth the high and low bid prices per share of our common stock, as reported on the OTC bulletin board for the periods indicated.

Quarter Ended	High	Low
December 31, 2006	$2.30	$1.50
March 31, 2007	$1.85	$0.96
June 30, 2007	$1.29	$0.46
September 30, 2007	$0.55	$0.16
December 31, 2007	$0.31	$0.15
March 31, 2008	$0.25	$0.12
June 30, 2008	$0.30	$0.15
September 30, 2008	$0.24	$0.11

On December 29, 2008 the last sale price for our common stock was $0.09.

Holders and Dividends

We have neither declared nor paid cash dividends on our capital stock and do not anticipate paying cash dividends in the foreseeable future. Our current policy is to retain cash to finance the exploration and development of our properties. Our Board of Directors will determine future declaration and payment of dividends, if any, in accordance with applicable corporate law.

As of December 31, 2008, there were 220 record holders of our common stock.

Recent Sales of Unregistered Securities

None

ITEM 6. SELECTED FINANCIAL DATA

Not Required by Form 10-K for Smaller Reporting Companies

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

The following discussion of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and notes appearing elsewhere in this Form 10-K.

Background

PetroHunter is considered a development stage company as defined by Statement of Financial Accounting Standards ("SFAS") 7, Accounting and Reporting by Development Stage Enterprises, as we have not yet commenced our planned principal operations. A development stage enterprise is one in which planned principal operations have not commenced, or if its operations have commenced, there have been no significant revenues to date.

From inception (June 2005) through our fiscal year ended September 30, 2007, we devoted our efforts to the acquisition of oil and gas properties and raising capital to fund such acquisitions. During the years ended September 30, 2006 and 2007, we operated and managed our properties in three groups: Heavy Oil, Piceance Basin and Australia. We determined at the end of our 2007 fiscal year that we needed to focus our operating efforts on our Buckskin Mesa and Beetaloo Basin Projects, as we lacked sufficient capital to develop our other properties. In addition, we had a $37.9 million working capital deficit as of September 30, 2007, which required us to secure additional debt financing and sell non-strategic assets. Accordingly, during the year ended September 30, 2008, we sold assets we did not consider to be central to our business plan in order to reduce a substantial accumulated working capital deficit and provide a path to achieve our future operating objectives in our core development projects. In addition, we sold certain working interests in our areas of focus in Australia and Colorado to Falcon Oil & Gas Ltd. ("Falcon"), a related party, with whom we plan to develop those properties. In August 2008, we entered into an agreement with Falcon to sell a 50% working interest in four exploration permits covering our 7.0 million-acre prospect in the Northern Territory, Australia (the "Beetaloo Basin"), and closed this transaction on September 30, 2008. We also entered into a binding agreement with Falcon to sell a 25% working interest in five wells located within our 20,000-acre Buckskin Mesa Project located in the Piceance Basin, Colorado, and to undertake a completion and testing program with respect to these five wells, and closed this transaction in November 2008.

The following discussion addresses our operating results for the years ended September 30, 2008, 2007 and 2006.

Results of Operations - Year Ended September 30, 2008 versus Year Ended September 30, 2007

Oil and Gas Revenues

Oil and gas revenues were $2.0 million and $2.8 million for the fiscal years ended September 30, 2008 and 2007, respectively, which represents a decline of $0.8 million or 29.3%. Oil and gas revenues decreased primarily due to our swap of acreage with EnCana (see Note 3) which reduced our net producing wells from 27 in 2007 to eight wells in 2008. In 2008, we sold 287,000 Mcf of natural gas and 348 Bbls of oil, and in 2007, we sold approximately 457,000 Mcf of natural gas and 137 Bbls of oil. Our natural gas volumes decreased by 37.2%, while our oil sales remained insignificant. The average price received for our natural gas sales in 2008 was $6.82 per Mcf, versus $6.16 per Mcf in 2007, representing an increase of $0.66 or 10.7%. We also generated $0.2 million in consulting revenue in 2008 under an agreement with a third party.

Costs and Expenses.

Lease Operating Expenses. Lease operating expenses of $0.8 million in 2008 include expenses on the remaining producing wells (our eight EnCana operated wells) of $0.5 million, and $0.3 million relating to compression charges on our Buckskin Mesa wells which are not yet producing, and are awaiting completion. We have incurred certain operating costs in anticipation of completing our five wells in our Buckskin Mesa Project, which has been delayed due to our cash flow constraints. This compares to $0.8 million of total lease operating expenses in 2007, which solely related to our producing wells.

General and Administrative. During 2008, general and administrative expenses decreased by $7.3 million or 40.6% in comparison to 2007. The following table highlights the areas with the most significant changes ($ in thousands):

	Year Ended September 30, 2008	Year Ended September 30, 2007	Change
Payroll	$ 2,572	$ 2,346	$ 226
Consulting fees	1,936	2,887	(951)
Stock based compensation expense	3,276	8,172	(4,896)
Legal	906	1,419	(513)
Travel	224	1,193	(969)
Investor relations	250	709	(459)
Insurance	575	325	250
Office operations	314	457	(143)
Other Miscellaneous	689	567	122
Total	$ 10,742	$ 18,075	$ (7,333)

Taken together, our payroll-related costs and consulting costs in 2008 declined $0.7 million to $4.5 million, from $5.2 million in 2007. This 13.9% decline was due to lower property development activity during 2008 and our efforts to reduce overall expenses to conserve cash. The increase in payroll-related costs is the result of converting certain long-term consultants to employees in the latter part of 2008.

Our stock based compensation expense decreased 59.9% to $3.3 million in 2008, from $8.2 million in 2007, and this $4.9 million reduction represented the most significant component of our overall reduction in general and administrative expenses. The reduction in this non-cash expense was primarily due to lower initial grant values in 2008 resulting from our falling share price, and significant charges recorded in 2007 due to the acceleration of certain stock options granted to former employees.

Our legal fees in 2008 were $0.9 million, a decrease of $0.5 million, or 36.2% lower than in 2007, due primarily to a streamlining of certain relationships with outside counsel and a conscious effort to reduce the use of outside legal services in 2008.

Our travel costs of $0.2 million in 2008 were $1.0 million or 81.2% lower than the $1.2 million in costs we incurred in 2007 as a result of our conscious efforts to manage costs and conserve cash.

Our investor relations costs of $0.3 million in 2008 were $0.4 million or $64.7% lower than the $0.7 million in costs we incurred in 2007, due primarily to our focus on expense management. All other general and administrative costs taken together increased by $0.2 million, primarily due to increased insurance costs.

Project Development Costs — Related Party. Property development costs were $0.0 million in 2008 and $1.8 million in 2007, as a result of our restructuring of our agreements with MAB, which was effective January 1, 2007 (See Note 10 of Notes to Consolidated Financial Statements). Prior to January 1, 2007, we incurred monthly project development costs pursuant to our Development Agreement with MAB on a series of individual property agreements, which did not continue after December 31, 2006.

Impairment of Oil and Gas Properties. During 2008, we recorded an impairment of $30.8 million compared to $24.1 million in 2007. Costs capitalized for properties accounted for under the full cost method of accounting are subjected to a ceiling test limitation on the amount of costs included in the cost pool by geographic cost center. Costs of oil and gas properties may not exceed the ceiling which is an amount equal to the present value, discounted at 10%, of the estimated future net cash flows from proved oil and gas reserves plus the cost, or estimated fair market value, if lower, of unproved properties. Should capitalized costs exceed this ceiling, an impairment is recognized representing the excess of capitalized costs over the ceiling, as calculated in accordance with the full cost accounting rules. The impairment in 2008 primarily resulted from the sale of oil and gas properties with significant proved reserves, offset in part by an increase in natural gas prices in 2008. The impairment in 2007 was primarily caused by an increase to the cost pool in the amount of $94.5 million, most of which was related to the fair value of the shares given up to MAB to increase our interest in several properties and as a result of the Consulting Agreement and amendments thereto. In accordance with GAAP, the shares were valued based on their market price on the date of issuance, which was $1.62 per share.

Depreciation, Depletion, Amortization and Accretion. Depreciation, depletion, amortization and accretion expense ("DD&A") was $1.2 million in 2008 and 2007. Depletion is based on the production volumes described above and declined slightly in 2008 to $0.9 million from $1.0 million in 2007. Depreciation expense was slightly higher in 2008 at $0.3 million compared to $0.2 million in 2007, as the evaluated asset pool increased for the balance of the year.

Losses on Conveyances of Property. During 2008, we completed several significant asset sales, which resulted in our recognizing losses of $20.5 million in accordance with the full cost pool accounting rules. During our first quarter ended December 31, 2007, we sold our Heavy Oil Projects and realized net proceeds of $13.0 million. The disposition of these assets was significant in relation to our U.S. full cost pool, and therefore, we were required to evaluate whether the transaction had significantly altered the relationship between our capitalized costs and proved reserves, which could cause us to recognize a loss under the full cost pool accounting rules. Accordingly, our evaluation resulted in our recognition of an $11.9 million loss on conveyance during the quarter ended December 31, 2007. Similarly, during our third quarter ended June 30, 2008, we sold the majority of our properties in the Southern Piceance Basin in Colorado, and realized net proceeds of $18.7 million. This transaction also required us to conduct a loss evaluation, upon which we concluded that this transaction also resulted in the recognition of an $8.6 million loss on conveyance during the quarter ended June 30, 2008. During 2007, we did not have any oil and gas property dispositions (See Note 3 of Notes to Consolidated Financial Statements).

Interest Expense. During 2008, interest expense was $11.2 million, in comparison to $6.7 million incurred in 2007. The $4.5 million net increase in interest expense, or 67.6%, primarily relates to the following: increased interest expense of $4.4 million associated with our credit facilities with Global Project Finance AG in 2008, versus $2.1 million incurred in 2007 resulting from a partial year the debt was outstanding in 2007, and additional borrowings in 2008; interest expense of $0.6 million on our convertible debentures in 2008 with none in 2007; and increased amortization of debt discounts and issuance costs of $4.0 million in 2008 versus $1.0 million in 2007; all partially offset by a $1.9 million decrease in interest on accounts and contracts payable aggregating $1.6 million in 2008 versus $3.5 million in 2007.

Net Loss. Our net loss of $76.9 million in 2008 compared to the loss of $49.8 million in 2007 represents an increase of $27.1 million or 54.3%, as a result of the factors above.

Year Ended September 30, 2007 vs. Year Ended September 30, 2006

Oil and Gas Revenues. Our initial revenues were generated during 2006 in the amount of $35,656. The 2006 revenues resulted from the initial testing and production of four natural gas wells in the Piceance Basin of Colorado that sold 5,822 Mcf of natural gas. Revenues increased to $2.8 million for the 2007 fiscal year. The increase is related to our earning revenue on our interest in certain producing wells, operated by a third party, in the Piceance Basin, Colorado. In 2007, these producing wells produced and sold approximately 457,000 Mcf of natural gas and 137 Bbls of oil. Average prices received for gas sold increased to $6.16 per Mcf in 2007 from $6.12 per Mcf in 2006 as a result of market conditions.

Costs and Expenses
Lease Operating Expenses. For 2007, lease operating expenses increased to $0.8 million compared to $0.0 million in 2006. This is a result of the fact that we had only performed testing on the four wells that we earned revenue from in 2006 while those same wells were operating for the full year during 2007.

General and Administrative. During 2007, general and administrative expenses increased by $4.4 million or 33% in comparison to 2006. The following table highlights the areas with the most significant increases ($ in thousands):

	Year Ended September 30, 2007	2006	Change
Payroll	$ 2,346	$ 846	$ 1,500
Consulting fees	2,887	1,292	1,595
Stock based compensation expense	8,172	9,189	(1,017)
Legal	1,419	550	869
Travel	1,193	759	434
Investor relations	709	553	156
IT maintenance and support	205	13	192
Total	$ 16,931	$ 13,202	$ 3,729

The increase in general and administrative expenses in 2007 is a result of commencing operations and hiring full-time employees in June 2006. We also experienced increased legal fees and travel expenses due to additional business and financing transactions, along with increased development activities in Australia and Colorado. There were no individually significant changes or trends in all other general and administrative costs not included in the above table.

Project Developmental Costs — Related Party. Property costs incurred to MAB were $1.8 million during 2007, as compared to $4.5 million in 2006, a decrease of $2.7 million or 60%. These costs decreased as a result of the restructuring of our agreements with MAB, which was effective January 1, 2007.

Impairment of Oil and Gas Properties. Costs capitalized for properties accounted for under the full cost method of accounting are subjected to a ceiling test limitation to the amount of costs included in the cost pool by geographic cost center. Costs of oil and gas properties may not exceed the ceiling which is an amount equal to the present value, discounted at 10%, of the estimated future net cash flows from proved oil and gas reserves plus the cost, or estimated fair market value, if lower, of unproved properties. Should capitalized costs exceed this ceiling, an impairment is recognized. During 2007, we recorded an impairment expense of $24.1 million, representing the excess of capitalized costs over the ceiling, as calculated in accordance with these full cost rules. The impairment in 2007 was primarily caused by an increase to the cost pool in the amount of $94.5 million, most of which was related to the fair value of the shares given up to MAB to increase our interest in several properties and as a result of the Consulting Agreement and amendments thereto.

Depreciation, Depletion, Amortization and Accretion. Depreciation, depletion, amortization and accretion expense (“DD&A”) was $1.2 million in 2007 as compared to $0.1 million in 2006. The increase is primarily a result of a higher amortization base in 2007.

Interest Expense. During 2007, interest expense was $6.7 million, as compared to $2.5 million during 2006. During 2007, interest expense included $3.4 million of costs paid to extend the Maralex Agreement and $1.0 million of amortization of discount and deferred financing costs on the credit facilities entered into during the year.

Net Loss. During 2007, we incurred a net loss of $49.8 million as compared to a net loss of $20.7 million during 2006.

Going Concern

The report of our independent registered public accounting firm on the financial statements for the year ended September 30, 2008, includes an explanatory paragraph relating to significant doubt or uncertainty of our ability to continue as a going concern. From our inception to September 30, 2008, we have generated a cumulative net loss of $149.5 million, we have a working capital deficit of $3.9 million as of September 30, 2008, we have obtained waivers of the covenants of several loan agreements to avoid defaults, and have significant capital expenditure commitments. For our 2009 fiscal year, we do not expect our operations to generate sufficient cash flows to provide working capital to pay overhead expenses, the funding of our lease acquisitions, and the exploration and development of our properties. Without adequate financing, we may not be able to successfully develop prospects that we have or that we acquire and we may not achieve profitability from operations in the near future or at all. We require significant additional funding to sustain our operations and satisfy our contractual obligations for our planned oil and gas exploration and development operations. Our ability to establish ourselves as a going concern is dependent upon our ability to obtain additional funding in order to finance our planned operations.

Schedule of Contractual Commitments

The following table summarizes the Company's obligations and commitments to make future payments under its notes payable, operating leases, employment contracts, consulting agreements and service contracts for the periods specified as of September 30, 2008 ($ in thousands):

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Related party notes	43,478	3,572	39,800	106	-
Long-term borrowings	7,236	280	-	6,956	-
Office leases	990	340	582	68	-
Compressor rentals	2,748	871	1,877	-	-
Drilling and seismic commitments	72,600	25,800	43,100	2,400	1,300
Total	$ 127,052	$ 30,863	$ 85,359	$ 9,530	$ 1,300

Plan of Operation

Colorado

In fiscal year 2009 we will focus on completing the five wells drilled in 2006-2007, and connect them to the gathering system, followed by drilling nine additional obligation wells, which must be commenced by December 31, 2009. Completion of the gathering system and central facility for the Buckskin Mesa Project will also enable us to recomplete and hook-up one or more of the six additional shut-in gas wells acquired with the properties in 2006.

Extensive regulatory compliance work has been initiated to facilitate our asset development plan, and some title issues are being addressed in connection with the drilling program for the fiscal year 2009. In summary, execution of the plan for these assets will optimally yield the drilling of not less than nine new exploratory wells in the Buckskin Mesa Prospect, and the completion or recompletion of as many as six wells in the Buckskin Mesa Prospect during fiscal year 2009.

Australia

We plan to explore and develop portions of our undivided 50% working interest in our 7.0 million acre position in four exploration permits in the Beetaloo Basin project area located in northwestern Australia. During calendar year 2009, we plan to drill four wells in the exploration permit blocks. We anticipate that costs related to seismic acquisition, development of operational infrastructure, and the drilling and completion of wells over the next twelve months, will aggregate approximately $18.5 million relating to our 50% working interest. We closed the sale of a 50% working interest in four exploration permits covering the above mentioned acreage to Falcon Oil and Gas Australia Pty Ltd. on September 30, 2008.

Liquidity and Capital Resources

Our most recent year ended September 30, 2008 was a year of significant transition for us. We began the year with a $37.9 million working capital deficit, and our cash flows from operations were not sufficient for us to meet our operating commitments. Our cash flows from operations continue to be, and are expected to continue to be, insufficient to meet our operating commitments through the year ending September 30, 2009.

Given these circumstances, our primary goals during 2008 were to significantly improve our balance sheet through the sale of non-core assets, pursue debt and equity financing transactions, and to seek development partners for our Buckskin Mesa Project in Colorado and our Beetaloo Basin Project in Australia. We made significant progress toward these goals during 2008. We were successful at raising $17.2 million through borrowings under our existing credit facilities and from the sale of convertible debentures; we realized net proceeds of $13.0 million through the sale of Our Heavy Oil Projects to Pearl Exploration and Production Ltd. in November 2007; we realized net proceeds of $18.7 million from the sale of all our interest in the Piceance II properties to Laramie Energy II, LLC, in

May 2008; and we completed the sale of the following interests in our properties pursuant to a purchase and sale agreement with Falcon Oil & Gas Ltd., dated August 25, 2008: (a) an undivided 50% working interest in four exploration permits in the Beetaloo Basin, Australia, which closed on September 30, 2008 and yielded net cash proceeds of $5.0 million and securities in the common stock of Falcon valued at $14.1 million as of September 30, 2008; and (b) an undivided 25% working interest in the five wells drilled in Buckskin Mesa, including the 40-acre tract surrounding each well, which closed on November 10, 2008, in exchange for a $7.0 million cash work commitment to complete certain of these wells. In addition, in December 2008, we completed the sale of our working interests in our eight producing wells operated by EnCana Oil & Gas (USA), Inc., for net cash proceeds of $2.3 million. As a result of our completion of these transactions, we reduced our working capital deficit to $3.9 million as of September 30, 2008.

In addition, as part of the Purchase and Sale Agreement with Falcon relating to our Buckskin Mesa property, Falcon obtained an option to acquire up to a 50% interest in our entire Buckskin Mesa Project, for total consideration of $28.5 million in cash or shares of Falcon common stock, and an $18.0 million work commitment ($9.0 million of which would be a carried interest for us). Further, Falcon may elect to become the operator of the Buckskin Mesa Project for an additional payment of $3.5 million. Falcon will have 60 days to determine whether it wishes to exercise the option after we have completed our testing program, which we expect will occur during our second quarter ending March 31, 2009. The exercise of this option would provide substantial additional liquidity to us.

In October 2008, we and Global Project Finance AG (“Global”) agreed that under certain circumstances, we may reduce the outstanding balance under the credit facilities with Global by up to $20.0 million in exchange for securities in Falcon and our common stock. If Falcon exercises its option to acquire a 50% interest in the Buckskin Mesa project and pays up to $10.0 million of the purchase price in Falcon convertible securities, we will assign to Global up to $10.0 million of such Falcon convertible securities, and pay the balance, if any, in cash, so that the total of the assigned Falcon convertible securities and any cash payment equals $10.0 million. Global has agreed to treat this assignment and payment as payment of $10.0 million against amounts owed under the Credit Facilities. In addition, upon exercise of the option, we would issue to Global shares of our common stock valued at $10.0 million as payment of an additional $10.0 million against amounts owed under the credit facilities.

Working Capital

Working capital is the amount by which current assets exceed current liabilities, and our working capital deficit is the result of having current liabilities in excess of our current assets. Our working capital is impacted by many factors, including changes in our oil and gas revenue production and changes in our ongoing operating costs, along with other business factors that affect our operating results and cash flows. Our working capital is also affected by the timing of operating cash receipts and disbursements, borrowings of and payments toward debt, expenditures for and sales of oil and gas properties, and increases and decreases in other assets involving cash.

As of September 30, 2008, we had a working capital deficit of $3.9 million and cash of $1.0 million, and as of September 30, 2007, we had working capital deficit of $37.9 million and cash of $0.1 million. Accordingly, we reduced our working capital deficit by $34.0 million during 2008. Included in current liabilities as of September 30, 2008 is a $4.8 million obligation we are contingently liable to pay to CCES Piceance Partners I, LLC upon our inability to reach mutual agreement on a commitment for our long term gas gathering system for our Buckskin Mesa Project. We expect we will be able to reach agreement with them, which would then release the guarantee, and we would then offset this obligation against the related intangible asset we have recorded as of September 30, 2008.

As of September 30, 2008, a total of $14.1 million of our $17.9 million in current assets related to shares of the common stock of Falcon Oil & Gas Ltd., which have declined significantly in value subsequent to September 30, 2008, and are subject to significant price volatility. In addition, the shares are traded on the Toronto Venture Exchange, and are denominated in Canadian Dollars, so they are also subject to changes in value due to changes in the value of the Canadian Dollar versus the U.S. Dollar. As of September 30, 2008, Falcon common shares were trading at CAD $0.55, resulting in a total value of $14.9 million (prior to a $0.8 million impairment we recognized due to an other than temporary decline in the value of certain of the shares based on management's plans and intentions), and as of January 9. 2009, Falcon common shares were trading at CAD $0.40, resulting in a total value of $9.7 million. Of the $5.2 million subsequent decline in value, $1.5 million of the decline was due to the strengthening of the U.S. Dollar against the Canadian Dollar, and $3.7 million of the decline was due to a drop in the market value of the shares.

In addition, a total of 14.5 million of the 28.9 million Falcon shares we have received in the Beetaloo Basin transaction are pledged as collateral for a $5.0 million loan we received from Falcon on October 1, 2008, and are reflected as restricted marketable securities on our consolidated balance sheet as of September 30, 2008. Substantially all of the proceeds of this loan were paid toward our outstanding vendor obligations as of September 30, 2008, included in accounts payable and accrued liabilities. The amount of cash we are ultimately able to realize upon the sale of these securities is a significant factor in our future liquidity and consequently will have a material effect upon our ability to meet our future cash commitments.

For our fiscal year ending September 30, 2009, we plan to fund our operating cash needs through: the sale of the Falcon stock; obtaining debt financing that is collateralized by the Falcon stock; seeking further sales of our remaining working interests in our Buckskin Mesa and Beetaloo Basin Projects; and/or completing additional private placements of debt or equity to raise cash to meet our working capital needs. A significant amount of capital is needed to fund our proposed drilling program for 2009 and to meet the balance of our operating cash needs.

Cash Flow – Year Ended September 30, 2008 versus Year Ended September 30, 2007

Net cash used in or provided by operating, investing and financing activities for the years ended September 30, 2008 and 2007 were as follows ($ in thousands):

	Year Ended September 30, 2008	2007
Net cash used in operating activities	$ (21,737)	$ (10,326)
Net cash used in investing activities	$ 14,145	$ (35,666)
Net cash provided by financing activities	$ 8,439	$ 35,483

Net Cash Used in Operating Activities. The changes in net cash used in operating activities are attributable to our net loss, adjusted for non-cash charges as presented in the consolidated statements of cash flows, together totaling ($12.7) million, plus an additional ($9.0) million in uses of working capital, which was primarily due to our payment of approximately $16.0 million of prior year property-related obligations to our vendors, partially offset by the non-cash conversion of $6.5 million of accrued interest on our Global credit facility to equity on September 30, 2008.

Net Cash Used in Investing Activities. Net cash used in investing activities for the year ended September 30, 2008 was primarily related to additions to oil and gas properties of $20.0 million, offset by proceeds of $31.9 million from the sale of various property interests and proceeds of $2.5 million from the sale of securities received in the sale of our Heavy Oil Projects.

Net Cash Provided by Financing Activities. Net cash provided by financing activities for the year ended September 30, 2008 was primarily comprised of: borrowings of $17.2 million under our Global credit facility, convertible notes, and other arrangements; net of $8.8 million of repayments on our various debt obligations other than to Global and our convertible debt holders.

Cash Flow – Year Ended September 30, 2007 versus Year Ended September 30, 2006

Net cash used in or provided by operating, investing and financing activities for the years ended September 30, 2007 and 2006 were as follows ($ in thousands):

Year Ended
September 30,

	2007	2006
Net cash used in operating activities	$ (10,326)	$ (10,546)
Net cash used in investing activities	$ (35,666)	$ (32,692)
Net cash provided by financing activities	$ 35,483	$ 52,620

Net Cash Used in Operating Activities. The changes in net cash used in operating activities are attributable to our net income adjusted for non-cash charges as presented in the consolidated statements of cash flows and changes in working capital as discussed above.

Net Cash Used in Investing Activities. Net cash used in investing activities for the year ended September 30, 2007 was primarily used for: (1) additions to oil and gas properties of $33.0 million; and (2) a $2.0 million earnest money deposit related to the proposed purchase of the Powder River basin assets that became a note receivable. Net cash used in investing activities for the year ended September 30, 2006 was primarily used for additions to oil and gas properties.

Net Cash Provided by Financing Activities. Net cash provided financing activities for the year ended September 30, 2007 was primarily comprised of: (1) borrowings of $32.3 million; and (2) the issuance of common stock subscriptions and common stock for $3.2 million. Net cash provided by financing activities for the year ended September 30, 2006 was comprised of: (1) the issuance of common stock and warrants of $36.4 million and (2) the issuance of convertible notes of $17.8 million offset by offering and financing costs of $1.6 million.

Capital Requirements

Uses of cash for 2009 will be primarily for our drilling programs in the Piceance Basin and in Australia. The following table summarizes our minimum drilling commitments for fiscal year 2009 ($ in thousands):

Activity	Prospect	Aggregate Total Cost	Our Working Interest	Our Share
Drill and complete 4 wells (a)	Buckskin Mesa	$ 9,600	100%	$ 9,600
Drill and complete 4 wells (b)	Piceance II	6,400	37.5%	2,400
Drill and complete 8 wells (c)	Beetaloo	27,600	50%	13,800
Total		$ 43,600		$ 25,800

(a) See Subsequent Events (Note 14 of Notes to Consolidated Financial Statements) for additional information on our sale of a portion of the Buckskin Mesa project area.

(b) Our proportionate share of the total commitment assumes our working interest partners pay their proportionate share.

(c) See Oil & Gas properties (Note 3 of Notes to Consolidated Financial Statements) for additional explanation on our sale of a 50% working interest in 2008. Reflects cost of eight-well commitment by December 31, 2009 that we expect to incur by September 30, 2009.

2008 Financing Transactions

During 2008, we completed financing transactions as follow:

(1) We borrowed $8.3 million on our credit facility with Global, for a total of $39.8 million as of September 30, 2008. The credit facility bears interest at prime plus 6.75%, which ranged from 14.0% at the beginning of the year to 11.8% at the end of the year. Accrued interest of $6.5 million at September 30, 2008 was converted to into 32.6 million shares of our common stock in lieu of cash payment. We pay an advance fee of 2% on all amounts borrowed under the facility, totaling $0.2 million during the year. As of September 30, 2008, we do not expect to obtain further funds from this facility and we are working with the lender to determine ways to satisfy the outstanding balance. The funds borrowed were used to fund working capital needs of the Company.

(2) In November 2007, we completed the sale of 8.5% convertible debentures to several accredited investors for an aggregate principal amount of $7.0 million, for which we received $6.3 million in cash proceeds. The remaining $0.7 million resulted from a transfer of $0.5 million or the $2.9 million common stock subscription outstanding at September 30, 2007 and $0.2 million of amounts converted from other accrued expenses. The debenture holders

also received five-year warrants to purchase 46.4 million shares of common stock. We paid a placement fee of $0.3 million. Funds were used to fund working capital needs.

(3) We borrowed $1.4 million from Global under short term promissory notes, which were unsecured and bore interest at 15% per annum. The funds were used primarily to fund working capital needs.

(4) We borrowed $0.9 million from vendors which was subsequently repaid during the year.

(5) We entered into four separate promissory notes with Bruner Family Trust, UTD March 28, 2005 for a total borrowing of $0.4 million in the current year. Each note bears interest at 8.0%. The funds were used to fund working capital needs. The remaining $2.3 million of the $2.7 million balance due to the Bruner Family Trust was converted from the $2.9 million common stock subscription outstanding as of September 30, 2007.

Other Cash Sources

The continuation and future development of our business will require substantial additional capital expenditures, and we believe we are actively pursuing all of our available options to generate cash. Meeting capital expenditure, operational, and administrative needs for the period ending September 30, 2009 will depend on our success in farming out or selling portions of working interests in our properties for cash and/or funding of our share of development expenses, the availability of debt or equity financing, and the outcomes of various uncertainties, including whether Falcon will exercise its option on our Buckskin Mesa properties. To limit capital expenditures, we may form industry alliances and exchange an appropriate portion of our interest for cash and/or a carried interest in our exploration projects using farm-out arrangements. We may need to raise additional funds to cover capital expenditures. These funds may come from cash flow, equity or debt financings, credit facilities, or sales of interests in our properties, although there is no assurance additional funding will be available or that it will be available on satisfactory terms. If we are unable to raise capital through the methods discussed above, our ability to execute our development plans will be greatly impaired.

Development Stage Company

We have not commenced our principal operations or earned significant revenue as of September 30, 2008, and we are considered a development stage entity for financial reporting purposes. During the period from inception to September 30, 2008, we incurred a cumulative net loss of $149.5 million. We have raised approximately $108.3 million through borrowing and the sale of convertible notes and common stock from inception through September 30, 2008. In order to fund our planned exploration and development of oil and gas properties, we will require significant additional funding.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our Financial Statements.

Reserve Estimates

Our estimates of oil and natural gas reserves, by necessity, are projections based on an interpretation of geological and engineering data. There are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geloogical interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, and the assumed effects of regulations by governmental agencies. Any significant variance in the assumtions could materially affect the estimated quantity and value of the reserves which could affect the carrying value of our oil and gas properties and/or the rate of depletion of the oil and gas properties.

Oil and Gas Properties

The Company utilizes the full cost method of accounting for its oil and gas properties. Under this method, subject to a limitation based on estimated value, all costs associated with property acquisition, exploration and development, including costs of unsuccessful exploration, are capitalized within a cost center on a by country basis. No gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas properties unless the sale represents a significant portion of oil and gas properties and the gain significantly alters the relationship between capitalized costs and proved oil and gas reserves of the cost center. Depreciation, depletion and amortization of oil and gas properties is computed on the units-of-production method based on proved reserves. Amortizable costs include estimates of future development costs of proved undeveloped reserves.

Capitalized costs of oil and gas properties may not exceed an amount equal to the present value, discounted at 10%, of the estimated future net cash flows from proved oil and gas reserves plus the cost, or estimated fair market value, if lower, of unproved properties. Should capitalized costs exceed this ceiling, an impairment is recognized. The present value of estimated future net cash flows is computed by applying year-end prices of oil and natural gas to estimated future production of proved oil and gas reserves as of year-end, less estimated future expenditures to be incurred in developing and producing the proved reserves and assuming continuation of existing economic conditions.

Asset Retirement Obligation

Asset retirement obligations associated with tangible long-lived assets are accounted for in accordance with SFAS 143, Accounting for Asset Retirement Obligations. The estimated fair value of the future costs associated with dismantlement, abandonment and restoration of oil and gas properties is recorded generally upon acquisition or completion of a well. The net estimated costs are discounted to present values using a risk adjusted rate over the estimated economic life of the oil and gas properties. Such costs are capitalized as part of the related asset. The asset is depleted on the units-of-production method on a field-by-field basis. The liability is periodically adjusted to reflect (1) new liabilities incurred, (2) liabilities settled during the period, (3) accretion expense, and (4) revisions to estimated future cash flow requirements. The accretion expense is recorded as a component of depreciation, depletion, amortization and accretion expense in the accompanying consolidated statements of operations.

Share Based Compensation

Effective October 1, 2006, we adopted the provisions of SFAS 123(R) (as amended), Share-Based Payment, using the modified prospective method, which results in the provisions of SFAS 123(R) being applied to the consolidated financial statements on a going-forward basis. SFAS 123(R) revises SFAS 123, Accounting for Stock-Based Compensation, and supersedes Accounting Principles Board (“APB”) Opinion 25, Accounting for Stock Issued to Employees. SFAS 123(R) establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods and services at fair value, focusing primarily on accounting for transactions in which an entity obtains employee services in share-based payment transactions. It also addresses transactions in which an entity incurs liabilities in exchange for goods and services that are based on the fair value of the entity’s equity instruments or that may be settled by the issuance of those equity instruments.

We have accounted for stock-based compensation awarded to non-employees under the provisions of EITF 96-18, Accounting for Equity Instruments That Are Issued to Other Than Employees for Acquiring, or in Conjunction with Selling, Goods or Services.

Impairment

SFAS 144, Accounting for the Impairment and Disposal of Long-Lived Assets, requires long-lived assets to be held and used to be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. We use the full cost method of accounting for our oil and gas properties. Properties accounted for using the full cost method of accounting are excluded from the impairment testing requirements under SFAS 144. Properties accounted for under the full cost method of accounting are subject to SEC Regulation S-X Rule 4-10, Financial Accounting and Reporting for Oil and Gas Producing Activities Pursuant to the Federal Securities Laws and the Energy Policy and Conversion Act of 1975 (“Rule 4-10”). Rule 4-10 requires that each regional cost center’s (by country) capitalized cost, less accumulated amortization and related deferred income taxes, not exceed a cost center “ceiling”. The ceiling is defined as the sum of:

- The present value of estimated future net revenues computed by applying current prices of oil and gas reserves to estimated future production of proved oil and gas reserves as of the balance sheet date less estimated future expenditures to be incurred in developing and producing those proved reserves to be computed using a discount factor of 10%; plus

- The cost of properties not being amortized; plus
- The lower of cost or estimated fair value of unproven properties included in the costs being amortized; less
- Income tax effects related to differences between the book and tax basis of the properties.

If unamortized costs capitalized within a cost center, less related deferred income taxes, exceed the cost center ceiling, the excess is charged to expense. During the periods ended September 30, 2008 and 2007, $30.8 million and $24.1 million was charged to impairment expense, respectively.

Marketable Securities

We received marketable equity securities as consideration from the sale of certain of our oil and gas properties, and account for them in accordance with SFAS 115, Accounting for Certain Investments in Debt and Equity Securities. As the shares we have received are available for sale in the short term, we account for them by marking them to market with unrealized gains and losses reflected as a component of Other Comprehensive Income, until such gains or losses become realized, when they will then be recognized in our statement of operations. In addition, in circumstances where significant price declines are experienced subsequent to the balance sheet date, we consider whether such declines are other than temporary, after considering our expected holding period, and may record a provision for impairment in the event we do not expect the value of the securities to recover from such a decline in market value. We consider our accounting for marketable securities to involve significant management judgment that is subject to estimation.

In November 2007, we received 1.5 million shares of the common stock of the purchaser of our Heavy Oil Projects, which were sold in March 2008, when we recognized a $3.0 million loss.

On September 30, 2008, we closed the sale of a 50% working interest in four of our exploration permits in Australia, and received 28.9 million shares of the common stock of the purchaser. Certain of these shares were subsequently pledged as collateral for a note, and are reflected as restricted marketable securities on our balance sheet as of September 30, 2008. In addition, we have recorded an estimated impairment of $0.8 million in relation to 2.8 million shares of unrestricted marketable securities, due to subsequent declines in the value of these shares that we consider to be other than temporary in light of our expected disposition date.

Recently Issued Accounting Pronouncements

In May 2008, the Financial Accounting Standards Board (the "FASB") issued Statement of Financial Accounting Standards ("SFAS") Statement No. 162, "The Hierarchy of Generally Accepted Accounting Principles", which identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of non-governmental entities that are presented in conformity with generally accepted accounting principles ("GAAP") in the United States. SFAS 162 is effective sixty days following the SEC's approval of The Public Company Accounting Oversight Board's related amendments to remove the GAAP hierarchy from auditing standards. We do not expect adoption of SFAS 162 will have a material impact on our Consolidated Financial Statements.

In May 2008, the FASB issued FASB Staff Position No. APB 14-1, Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement) (the FSP). The FSP specifies that issuers of convertible debt that can be settled in cash should separately account for the liability (debt) and equity (conversion option) components in a manner that reflects the entity’s nonconvertible debt borrowing rate when interest cost is recognized. The FSP therefore may require different accounting for our Convertible Debentures due 2012 issued in November 2007 upon the adoption of the FSP. We will adopt the FSP October 1, 2009. The provisions of the FSP will be applied retrospectively to all periods presented, or all periods subsequent to January 2007.

In March 2008, the FASB issued SFAS 161, Disclosures about Derivative Instruments and Hedging Activities, an Amendment of SFAS No. 133. This new standard requires enhanced disclosures about how and why an entity uses derivative instruments, how such instruments and related hedged items are accounted for under SFAS No. 133, and how those instruments and items affect an entity’s financial position, financial performance, and cash flows. We must adopt SFAS 161 no later than October 1, 2009. We currently have no derivatives outstanding as of September 30,

2008. The adoption of this standard may affect future disclosures related to any derivative instruments or related hedges that are entered into in future periods.

In December 2007, the FASB issued SFAS 141(R), Business Combinations, and SFAS 160, Accounting and Reporting of Non Controlling Interest in Consolidated Financial Statements, an Amendment to ARB No. 51. These new standards will significantly change the accounting for and reporting of business combination transactions and minority interests in financial statements. We must adopt these standards simultaneously as of October 1, 2009, for the beginning of the fiscal 2010 year. The adoption of these standards will have a material effect on the accounting for any business combination consummated thereafter or for any minority interest that exists at that time.

In February 2007, the FASB issued SFAS 159, The Fair Value Option for Financial Assets and Financial Liabilities, which allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in current earnings. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between entities that elect different measurement attributes for similar assets and liabilities. SFAS 159 became effective for us on October 1, 2008. We believe that the impact of SFAS 159 on our consolidated results of operations, cash flows or financial position is not material.

In September 2006, the FASB issued SFAS 157, Fair Value Measurements, which addresses how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under generally accepted accounting principles. We adopted SFAS 157 as of October 1, 2008. We will use fair value measurements to determine the reported amounts of assets acquired and liabilities assumed in purchase transactions, in testing potential goodwill, for disclosure of the fair value of financial instruments, and elsewhere. It is therefore possible that the implementation of SFAS 157 could have a material effect on the reported amounts or disclosures in our consolidated financial statements in future periods.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Not required by Form 10-K for Smaller Reporting Companies

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
PetroHunter Energy Corporation (a development stage company)
Denver, Colorado

We have audited the accompanying consolidated balance sheet of PetroHunter Energy Corporation (the “Company”), a development stage company, as of September 30, 2008 and the related consolidated statements of operations, stockholders’ equity and comprehensive loss and cash flows for the year then ended and the cumulative period from June 20, 2005 (inception) to September 30, 2008. We did not audit the cumulative period from June 20, 2005 (inception) to September 30, 2007. Those amounts were audited by other auditors, whose report dated January 11, 2008 has been furnished to us, and our opinion, insofar as it relates to the cumulative amounts from June 20, 2005 (inception) to September 30, 2007, is based solely on the report of the other auditors. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the company’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of PetroHunter Energy Corporation (a development stage company) as of September 30, 2008, and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

We have also audited the combination in the consolidated statements of operations, cash flows, and shareholders’ equity and comprehensive loss of the amounts as presented for the year ending September 30, 2008 with the amounts for the corresponding statements for the period from June 20, 2005 (inception) through September 30, 2007. In our opinion the amounts have been properly combined for the period from June 20, 2005 (inception) through September 30, 2008.

The accompanying financial statements have been prepared assuming that PetroHunter Energy Corporation will continue as a going concern, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of operations. As discussed in Note 2, certain factors indicate substantial doubt that the Company will be able to continue as a going concern. The financial statements do not include any adjustments to reflect the possible future effect on the recoverability and classification of assets or the amounts and classification of liabilities that might result from the outcome of these uncertainties.

As discussed in Notes 3, 6, 7, 9, 10 11, and 14, the Company had numerous significant transactions with related parties.

/s/ Eide Bailly LLP

Eide Bailly LLP

Greenwood Village, Colorado
January 12, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors
PetroHunter Energy Corporation
Denver, Colorado

We have audited the accompanying consolidated balance sheet of PetroHunter Energy Corporation and subsidiaries (the "Company"), a development stage company, as of September 30, 2007, and the related consolidated statement of operations, comprehensive loss, stockholders' equity and cash flows for the year ended September 30, 2007 and for the period from inception (June 20, 2005) to September 30, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provided a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of PetroHunter Energy Corporation and subsidiaries as of September 30, 2007, and the results of their operations and their cash flows for the year ended September 30, 2007 and for the period from inception (June 20, 2005) to September 30, 2007 in conformity with U.S. generally accepted accounting principles.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the financial statements, the Company has incurred recurring losses from operations, has a working capital deficit of approximately $37.8 million, was not in compliance with the covenants of several loan agreements, has had multiple property liens and foreclosure actions filed by vendors, and has significant capital expenditure commitments. These factors raise substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 2. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

As discussed in Note 2, effective October 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123(R), Share Based Payments.

As discussed in Notes 3, 6, 7, 10, 11 and 14, the Company has had numerous significant transactions with related parties.

/s/ Hein & Associates LLP

HEIN & ASSOCIATES LLP

Denver, Colorado
January 11, 2008

PETROHUNTER ENERGY CORPORATION
(A Development Stage Company)
CONSOLIDATED BALANCE SHEETS

ASSETS	September 30, 2008	2007
	($ in thousands)	
Current Assets		
Cash and cash equivalents	$ 967	$ 120
Receivables		
Oil and gas receivables, net	193	487
GST receivables	504	—
Other receivables	12	59
Due from related parties	1,840	500
Notes receivable – related party	—	2,494
Restricted marketable securities	7,495	—
Unrestricted marketable securities	6,638	—
Prepaid expenses and other assets	273	187
TOTAL CURRENT ASSETS	17,922	3,847
Property and Equipment, at cost		
Oil and gas properties under full cost method, net	97,352	162,843
Furniture and equipment, net	737	569
	98,089	163,412
Other Assets		
Joint interest billings	—	13,637
Restricted cash	524	599
Deposits and other assets	130	—
Deferred financing costs	1,388	529
Intangible asset	4,832	—
TOTAL ASSETS	$ 122,885	$ 182,024
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued expenses	$ 11,981	$ 26,631
Notes payable – short term	329	4,167
Note payable –related party – current portion	3,572	4,255
Note payable – long term – current portion	—	120
Accrued interest payable	166	2,399
Accrued interest payable related party	969	516
Due to shareholder and related parties	—	1,474
Contracts payable – oil and gas properties	—	1,750
Convertible notes payable	—	400
Contingent purchase obligation	4,832	—
TOTAL CURRENT LIABILITIES	21,849	41,712
Notes payable – related party – net	38,035	36,864
Notes payable	—	130
Convertible notes payable – net	325	—

Asset retirement obligation	114	136
TOTAL LIABILITIES	60,323	78,842
Commitments and Contingencies (Notes 3, 5, 6, 11 and 13)		
Common Stock Subscribed	—	2,858
Stockholders’ Equity		
Preferred stock, $0.001 par value; authorized 100,000,000 shares; none issued	—	—
Common stock, $0.001 par value; authorized 1,000,000,000 shares; 373,343,544 and 278,948,841 issued and outstanding at September 30, 2008 and 2007, respectively	374	279
Additional paid-in-capital	212,308	172,672
Accumulated other comprehensive loss	(632)	(5)
Deficit accumulated during the development stage	(149,488)	(72,622)
TOTAL STOCKHOLDERS’ EQUITY	62,562	100,324
TOTAL LIABILITIES AND STOCKHOLDERS’ EQUITY	$ 122,885	$ 182,024

See accompanying notes to consolidated financial statements.

PETROHUNTER ENERGY CORPORATION
(A Development Stage Company)

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended September 30, 2008	Year Ended September 30, 2007	Year Ended September 30, 2006	Cumulative from Inception (June 20, 2005) to September 30, 2008
	($ in thousands, except per share amounts)			
Revenues				
Oil and gas revenues	$ 1,993	$ 2,820	$ 36	$ 4,849
Other revenues	187	—	—	187
Total Revenue	2,180	2,820	36	5,036
Costs and Expenses				
Lease operating expenses	805	793	4	1,602
General and administrative	10,742	18,075	13,638	43,691
Project development costs — related party	—	1,815	4,530	7,205
Impairment of oil and gas properties	30,847	24,053	—	54,900
Depreciation, depletion, amortization and accretion	1,230	1,245	73	2,548
Total operating expenses	43,624	45,981	18,245	109,946
Loss from Operations	(41,444)	(43,161)	(18,209)	(104,910)
Other Income (Expense)				
Loss on conveyances of property	(20,469)	—	—	(20,469)
Foreign currency exchange gain	11	23	—	34
Interest income	65	36	3	104
Interest expense	(11,242)	(6,709)	(2,486)	(20,460)
Loss on sale of securities	(2,987)	—	—	(2,987)
Impairment of marketable securities	(800)	—	—	(800)
Total other expense	(35,422)	(6,650)	(2,483)	(44,578)
Net Loss	$ (76,866)	$ (49,811)	$ (20,692)	$ (149,488)
Net loss per common share — basic and diluted	$ (0.24)	$ (0.20)	$ (0.14)	
Weighted average number of common shares outstanding — basic and diluted	322,902,152	243,816,957	147,309,096	

See accompanying notes to consolidated financial statements

PETROHUNTER ENERGY CORPORATION
(A Development Stage Company)

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE LOSS

	Common Stock							
	Shares	Amount	Additional Paid-in Capital	Deficit Accumulated During the Development Stage	Accumulated Other Comprehensive Loss	Total Stockholders' Equity	Total Comprehensive Loss	Common Stock Subscribed
	($ in thousands)							
Balance, June 20, 2005 inception)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Shares issued to founder at $0.001 per share	100,000,000	100	—	—	—	100	—	—
Stock based compensation costs for options granted to non-employees	—	—	823	—	—	823	—	—
Net loss	—	—	—	(2,119)		(2,119)	(2,119)	—
Balance, September 30, 2005	100,000,000	100	823	(2,119)	—	(1,196)	(2,119)	—
Shares issued for property interests at $0.50 per share	3,000,000	3	1,497	—	—	1,500	—	—
Shares issued for finder's fee on property at $0.50 per share	3,400,000	3	1,697	—	—	1,700	—	—
Shares issued upon conversion of debt, at $0.50 per share	44,063,334	44	21,988	—	—	22,032	—	—
Shares issued for commission on convertible debt at $0.50 per share	2,845,400	3	1,420	—	—	1,423	—	—
Sale of shares and warrants at $1.00 per unit	35,442,500	35	35,407	—	—	35,442	—	—
Shares issued for commission on sale of units	1,477,500	1	1,476	—	—	1,477	—	—

Costs of stock offering:	—	—	—	—	—	—	—	—
Cash	—	—	(1,638)	—	—	(1,638)	—	—
Shares issued for commission at $1.00 per share	—	—	(1,478)	—	—	(1,478)	—	—
Exercise of warrants	1,000,000	1	999	—	—	1,000	—	—
Recapitalization of shares issued upon merger	28,700,000	30	(436)	—	—	(406)	—	—
Stock based compensation	—	—	9,189	—	—	9,189	—	—
Net loss	—	—	—	(20,692)	—	(20,692)	(20,692)	—
Balance, September 30, 2006	219,928,734	220	70,944	(22,811)	—	48,353	(20,692)	—
Common stock subscribed	—	—	—	—	—	—	—	2,858
Shares issued for property interests at $1.70 per share	2,428,100	2	4,125	—	—	4,127	—	—
Shares issued for property interests at $1.62 per share	50,000,000	50	80,950	—	—	81,000	—	—
Shares issued for property interests at $1.49 per share	256,000	—	382	—	—	382	—	—
Shares issued for commission costs on property at $1.65 per share	121,250	—	200	—	—	200	—	—
Shares issued for finance costs on property at $1.72 per share	571,900	1	984	—	—	985	—	—
Shares issued for finance costs on property at $1.29 per share	475,000	—	612	—	—	612	—	—
Shares issued for finance costs on property at $0.70 per share	642,857	1	449	—	—	450	—	—
Shares issued for finance costs on property	525,000	1	268	—	—	269	—	—

at $0.51 per share								
Shares issued for finance costs on property at $0.23 per share	4,000,000	4	916	—	—	920	—	—
Foreign currency translation adjustment	—	—	—	—	(5)	(5)	(5)	—
Discount on notes payable	—	—	4,670	—	—	4,670	—	—
Stock based compensation	—	—	8,172	—	—	8,172	—	—
Net loss	—	—	—	(49,811)	—	(49,811)	(49,811)	—
Balance, September 30, 2007	278,948,841	279	172,672	(72,622)	(5)	100,324	(49,816)	2,858
Shares returned for property conveyance at $0.22 per share	(6,400,000)	(6)	(1,402)	—	—	(1,408)	—	—
Shares issued for property interests at $0.31 per share - related party	25,000,000	25	7,725	—	—	7,750	—	—
Shares issued in connection with debt conversion at $0.23 per share – related party	16,000,000	16	3,664	—	—	3,680	—	—
Shares issued for property conveyance at $0.25 per share	5,000,000	5	1,245	—	—	1,250	—	—
Shares issued for finance costs at $0.28 per share	200,000	—	56	—	—	56	—	—
Shares issued for conversion of convertible debt at $0.20 per share	2,677,519	3	533	—	—	536	—	—

Common shares issued for conversion of accrued interest – related party at $0.20 per share	32,600,075	33	6,487	—	—	6,520	—	—
Shares issued for vendor settlements at $0.20 per share	16,879,219	17	3,359	—	—	3,376	—	—
Shares issued for finance costs at $0.18 per share	2,037,890	2	365			367		
Shares issued for purchase option at $0.20 per share	400,000	—	80	—	—	80	—	—
Discount associated with beneficial conversion feature and detachable warrants on convertible debenture issuance	—	—	6,956	—	—	6,956	—	—
Warrant value associated with convertible debenture issuance	—	—	21	—	—	21	—	—
Warrant value associated with debt conversion – related party	—	—	1,841	—	—	1,841	—	—
Debt conversion - related party	—	—	2,704	—	—	2,704	—	—
Recognition of warrant value associated with amendment & waiver on convertible debt	—	—	495	—	—	495	—	—
Discount on notes payable	—	—	336	—		336		
Stock based compensation	—	—	3,276	—	—	3,276	—	—
Origination fees associated with debt issuance	—	—	1,895	—		1,895		
Foreign currency translation adjustment	—	—	—	—	(627)	(627)	(627)	—
Net loss	—	—	—	(76,866)	—	(76,866)	(76,866)	—
Balance, September 30, 2008	373,343,544	$ 374	$ 212,308	$ (149,488)	$ (632)	$ 62,562	$ (77,493)	

See accompanying notes to consolidated financial statements.

PETROHUNTER ENERGY CORPORATION
(A Development Stage Company)

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended September 30, 2008	Year Ended September&#